HECO T-20
DOCKET NO. 2006-0386

TESTIMONY OF
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ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Cost-of-Service Study and Rate Design

INTRODUCTION

Q. Please state your name and business address.

A. My name is Peter C. Young, and my business address is 220 South King Street, Suite 1201, Honolulu, Hawaii, 96813.

Q. What is your present position with the Company?

A. I am the Director of Pricing Division, Energy Services Department, Hawaiian Electric Company, Inc. My experience and educational background are listed in HECO-2000.

Q. Have you testified before the Commission in prior Company proceedings?

A. Yes. I have appeared as the Company's witness on test-year revenues, rate design, and cost-of-service study in several prior rate proceedings listed in HECO-2000.

Q. What is your area responsibility in this proceeding?

A. My testimony will discuss HECO's cost-of-service studies, proposed rates, and proposed changes to the Company's rules.

COST-OF-SERVICE STUDIES

Q. What is a cost-of-service study?

A. A cost-of-service study is a tool used to determine the cost responsibility of the different rate classes served by HECO for ratemaking purposes. Two types of cost studies were prepared for this proceeding, one based on embedded or accounting costs, and the other is based on marginal costs. Although both studies reflect the costs of providing service, the procedure and emphasis of each of these two studies are different.

Q. What is the difference between an Embedded Cost-of-Service Study and a

Marginal Cost Study?

A. An Embedded Cost-of-Service Study (simply referred to as a cost-of-service study) is a process used to categorize and allocate the total utility costs of providing service (the utility's total revenue requirements) to the various rate classes in order to determine each class's costs responsibility. In contrast, a Marginal Cost Study determines the change in the utility's costs of providing service due to a unit change in kilowatts ("kW"), kilowatthours ("kWh"), or number of customers served by the utility.

RESULTS OF THE EMBEDDED COST-OF-SERVICE STUDY

Q. What costs are included in the cost-of-service study?

A. The cost-of-service study is based on embedded or accounting costs, and includes all the costs incurred in providing electric service to customers. It includes the test-year estimates of operation and maintenance expenses, depreciation expenses, taxes, plant costs, and return on capital.

Q. How are the results of the cost-of-service study presented?

A. The summary exhibits separately compare the results at present rates, which are the base rates approved in HECO's 1995 test year case, and the results at current effective rates, which are the same base rates plus the interim rate increase approved in HECO's 2005 test year case, with the results at proposed rates.

Q. What are the results of the cost-of-service study?

A. The results of the cost-of-service study are summarized in the following exhibits:

1. HECO-2001 compares the classes' revenues and rates of return at present rates and current effective rates versus the classes' revenue and rates of return at proposed rates;

2. HECO-2002 provides the determination of the classes' rates of return at present rates, current effective rates; and proposed rates;
3. HECO-2003 show summaries of the proposed allocation of rate increase by rate class, from both present rates and current effective rates;
4. HECO-2004 show summaries of the classes' revenue requirements differences at equal rates of return at both present rates and current effective rates;
5. HECO-2005 shows summaries of the classes' proposed revenue requirements and rates of return;
6. HECO-2006 is a summary of the classes' functionalized sales revenue requirements at proposed rates;
7. HECO-2007 is a summary of the classes' unit functionalized sales revenue requirements at proposed rates;
8. HECO-2008 is a summary of the classes' functionalized sales revenue requirements at equal rates of return; and
9. HECO-2009 is a summary of the classes' unit functionalized sales revenue requirements at equal rates of return.

Q. Please discuss the classes' revenues and rates of return presented in HECO-2001.

A. HECO-2001 shows that the total operating revenues at present rates and at proposed rates are $1,350,277,000 and $1,501,782,800, respectively, which reflects a total proposed increase of $151,505,800, or 11.22%. Total operating revenues at current effective rates, which are the present rates plus the interim rate increase approved in Docket No. 04-0113, are $1,402,226,100, which requires an increase of $99,556,700 to attain the total operating revenues at proposed rates.

Q. What are the differences between the class rates of return at present rates, current effective rates, and at proposed rates?

A. The results of operation for test-year 2007 show a system rate of return on rate base of 1.98% at present rates and 4.36% at current effective rates, as shown in HECO-2001.

Under the proposed rates, the system rate of return is 8.92% and the classes' rates of return range from 3.67% for Schedule F to 12.12% for Schedule J. Schedule PS provides the second highest rate of return of 11.67% under the proposed rates, followed by Schedule PP and Schedule PT with 11.50% and 10.59%, respectively. These are summarized in HECO-2001, page 2.

Q. Please describe how the proposed allocation of the revenue increase among the rate classes was determined.

A. The proposed allocation of the revenue increase among the rate classes is summarized in HECO-2003, and is based on assigning an across the board increase of 7.06% to all the rate classes from current effective rates. The assignment of the same percent rate increase to all the rate classes is discussed in HECO T-1.

Q. Please discuss the required class revenue requirements at equal rates of return presented in HECO-2004.

A. The classes' revenue requirements that result in the class rates of return equal to the system rate of return are generally referred to as the classes' full cost-of-service. The proposed total revenue requirements of $1,501,782,800 result in the proposed system rate of return on rate base of 8.92%. HECO-2004 provides a summary of the classes' revenue requirements and rate increase that would result with each class providing the same 8.92% rate of return on rate base. For instance, Schedule R's revenue requirement at 8.92% rate of return is

$493,506,000, which would require a 13.98% rate increase over current effective rates for Schedule R. A summary comparison of the classes' revenue requirements and rates of return at present rates (page 1) and current effective rates (page 2), at proposed rates, and at the classes' full cost-of-service is provided in HECO-2005.

EMBEDDED COST-OF-SERVICE STUDY METHODOLOGY

Q. How is the embedded cost-of-service study developed?

A. The cost-of-service study involves three major steps in determining the classes' cost responsibility, namely:

1. Functionalization of costs and rate base items into the major operating functions of production, transmission, and distribution.
2. Classification of the functionalized costs into the three cost components of energy-related costs, demand-related costs, and customer-related costs.
3. Allocation of the costs components to the different rate classes.

Each of these three steps involves detailed analysis to develop the appropriate bases and factors for classifying and allocating costs.

FUNCTIONALIZATION OF COSTS

Q. Can you briefly explain the process of functionalizing costs?

A. The functionalization process categorizes the different costs and rate base items into the major operating functions of (a) production, (b) transmission, and (c) distribution. This process enables the identification of the utility facilities and/or services that are provided to serve particular rate classes and thereby facilitate the assignment of costs.

Q. What costs are included in each operating function?

A. The costs included in each operating function are:

1. Production function costs include all costs associated with generating power including fuel costs and purchased power expense.
2. Transmission function costs include all costs associated with transferring power from power plants to substations or between switching stations at transmission voltage levels.
3. Distribution function costs include all costs associated with delivering power from the transmission voltage levels through the distribution system to the customer, and connecting the customers to the system. The distribution function is further categorized into the sub-functions of (a) substations, (b) primary lines, (c) secondary lines, (d) transformers, (e) service drops, (f) meters, (g) customer accounting, and (h) customer services. The sub-functionalization facilitates the allocation of the costs of these facilities and services to the different rate classes.

Q. How are the costs broken down into these functions and sub-functions?

A. HECO records costs using the NARUC Uniform System of Accounts, which directly assigns some cost items to these functional categories. The costs associated with plant-in-service and most of the operation and maintenance expenses can be readily functionalized by account number analysis. Some costs, such as those related to general plant, administrative and general expenses, taxes, and return on capital, are not recorded by functional accounts and are not directly assigned to the major functions. These general type costs are categorized into the three major functions by analysis of their characteristics or by using an appropriate functionalization base. The breakdown of the distribution function costs into the primary and secondary voltage sub-functions is based on HECO's recorded distribution facilities costs from 1985-2003, where available.

CLASSIFICATION OF COSTS

Q. Please describe the second step of the study, the classification of costs.

A. In the classification process, each of the functionalized costs and rate base items are then classified into each of the three costs components: (a) energy-related, (b) demand-related, and (c) customer-related. This process further categorizes the costs based on what causes them to be incurred to facilitate their allocation to the various rate classes based on measurable service characteristics, such as kilowatthour consumption, kilowatt demand, and number or type of customers connected to the system.

Q. What costs are included in each of the three costs components?

A. The costs included in each of the three costs components are:

1. Energy-related costs include those costs that are incurred to produce the kilowatthour energy (kWh) used by the customers such as fuel and purchase power costs. These costs vary with the volume of kWh generated by the system.
2. Demand-related costs include those costs that are incurred to serve the customers' kilowatt demand (kW) on the utility system. The capacity size of the plant facilities is determined by the customers' kW demand on the system.
3. Customer-related costs include those costs that are incurred in order to connect the customers to the system, bill them, and maintain their service accounts, regardless of their energy consumption (kWh) or demand (kW)

on the system. These costs are related to the number and type of customers, and consist of plant-related and service-related customer costs. The plant-related customer costs are the customer cost component of the distribution lines and distribution transformers costs, and the costs of service drops and meters. The service-related customer costs are the costs of meter reading, customer billing and accounting, and customer service related expenses.

Q. How are those costs that are not directly related to kWh, kW, and/or number and type of customers, categorized to the three cost components?

A. Some costs, such as taxes, are related to revenues or payroll rather than to kWh, kW, or number of customers. Revenue-related costs are directly allocated to the various rate classes based on the revenues generated from each rate class, or on the basis of the allocated O&M labor expense.

Q. Please describe how each functionalized cost is classified into the three costs components?

A. The classification of each functionalized cost is based on the NARUC Electric Utility Cost Allocation Manual dated January 1992. Following the NARUC cost classification rationale, the production function costs are classified to demand and energy components. The energy components primarily include the fuel-related expense and the energy component of the purchased power expense.

The transmission function costs are classified to demand components since the transmission systems are generally sized to meet the maximum kW loads on the system.

The distribution function costs are classified to demand and customer components. Some distribution facilities or equipment, such as the service drops and meters, are required to connect and serve the customers regardless of their kW demand, and are therefore appropriately classified to customer components. Distribution substations are normally classified as demand-related, because these facilities are normally built to serve particular load sizes and are not affected by the number of customers to be served. The distribution lines and transformers are assigned to demand and customer components, since the size and cost of these facilities are dependent not only on the customers' load, but also on the type and location of the customers.

Q. How is the customer component of the distribution lines and transformers determined?

A. The customer component of the distribution lines and transformers is that portion of costs which varies with the number and location of customers. Following the NARUC cost allocation manual, HECO has used the Minimum Size Method to allocate these costs to customer-related and demand-related components.

Q. Please briefly describe the Minimum Size Method.

A. The Minimum Size Method assumes that a minimum size distribution system can be built to serve the customers' minimum service requirements. The cost of the minimum size facility, such as the minimum size pole, conductors, and transformers installed by the utility is classified as the customer-related component of these facilities. The demand-related component is the difference between the total costs of these facilities and the customer-related component.

Q. Did HECO perform a minimum size method analysis for the cost-of-service study?

A. HECO prepared a minimum size method analysis for use in the cost-of-service study in the 2005 test year case. The results of that minimum size method analysis are used in the cost-of-service study in this case as well.

ALLOCATION OF COSTS

Q. How is each of the three costs components allocated to the different rate classes?

A. After each cost function has been assigned to the three costs components, each cost component is then allocated to the different rate classes based on the causative service variable. For instance, the energy-related cost component varies with the kWh generated by the utility, and is therefore allocated to the different rate classes based on the classes' kWh consumption. The demand-related cost component varies with kW load, and is allocated to the different rate classes based on the classes kW demand. The customer-related cost component is determined by the number and/or type of customers, and is therefore allocated to the different rate classes based on the number of customers in each rate class, weighted to reflect the differences in various customer-related services and/or activities. The weighting factors reflect differences in service phase, service voltage, metering requirements, and complexity of meter reading, billing, and accounting services.

A summary of the allocation factors for the three costs components is provided in HECO-2010.

Q. Please explain how the energy allocation factors used to allocate the energy-related costs were derived?

A. The energy allocation factors are based on the test-year kWh sales forecasts for each rate class, and adjusted for line losses. These line losses are added to the kWh sales since HECO's fuel and purchased energy costs are related to the energy input to the system. The determination of the classes' kWh usage including line losses, used in the determination of the energy allocation factors, is provided in

HECO-2011.

Q. How were the demand allocation factors, used to allocate the demand-related costs, derived?

A. The demand-related cost component is related to the kW demand served by the system, and is therefore allocated on the basis of the customers' kW load. Unlike the allocation of the energy-related and customer-related costs, there are different methods of allocating demand costs. The three main demand cost allocation methods are the: (a) Average-Excess Demand Method (AED Method), (b) Peak Responsibility Method (PR Method), and (c) Non-Coincident Demand Method (NCD Method). All other methods are simply variations or combinations of these three major demand cost allocation methods.

Q. What are the differences between these three methods?

A. Each demand cost allocation method is based on different premises as to the primary determinant of the demand-related cost that determines how customer classes contribute to the utility's demand costs.

The AED Method assumes that the utility system capacity requirement is determined not only by the maximum kW demand but also by other factors such as the system load factor and demand diversity factor. It considers both the kW load and the kWh energy consumption in allocating the demand costs. This method allocates the demand costs on the basis of each class's average demand (kWh Consumption ÷ No. of Hours) weighted by the system load factor, and the class's excess demand (Class Peak Demand – Average Demand) weighted by 1 minus the system load factor.

The PR Method assumes that the utility system capacity requirement is determined by the system peak load. This method allocates the demand cost on the basis of each class' contribution to the system peak.

The NCD Method assumes that each customer class, if served independently, will require facilities that would meet the class' maximum demand. It therefore allocates the demand costs based on the classes' maximum demands or class non-coincident peaks during the year regardless of when they occur.

Q. What demand cost allocation method did HECO use in its cost-of-service study for this proceeding?

A. As in Docket No. 04-0113, test year 2005, HECO used the AED method to allocate the production and transmission demand costs, and the NCD method to allocate the distribution demand costs. These methods have been used in the Company's prior rate cases (including HELCO's and MECO's), and have been found reasonable and approved by the Commission.

Q. Why did HECO use the AED Method to allocate the production and transmission demand costs?

A. The AED Method considers several factors in allocating demand costs and results in relatively more stable results, unlike the other two major demand costs allocation methods, which consider only one demand parameter in allocating demand costs. The AED Method considers the classes' demand requirements, energy consumption, and system load factor in allocating the demand costs. Given HECO's system load profile with low seasonality and broad peak periods, the AED Method has proven to be reasonable for HECO.

Q. Why did HECO use the NCD Method to allocate the distribution demand costs?

A. HECO used the NCD Method to allocate the distribution demand costs because the distribution facilities are sized to serve the maximum diversified demand at these service levels regardless of the system peak load.

Q. What load data did you use to develop the allocation factors used in the cost-of-service study.

A. The allocation factors used in the cost-of-service study are based on the results of HECO's 2003 Class Load Study. These results were also used to develop allocation factors for the cost-of-service study in Docket No. 04-0113, HECO's 2005 test year rate case. The class load study is based on a total sample of 486 customers across all rate classes, except Schedule F. The study collected 15-minute load data from the selected sample for the entire calendar year 2003.

MARGINAL COST STUDY

Q. What are the results of the Marginal Cost Study?

A. HECO prepared a marginal cost study for Docket No. 04-0113, test year 2005. The marginal demand costs and marginal customer-related costs from that study are repeated in this docket. The marginal demand costs and marginal customer-related costs are compared against the average unit embedded costs at equal rates of return in HECO-2012. The marginal energy costs were revised for changes in the estimated hourly running costs for the five-year period from 2007 to 2011, from the production simulation model. The model simulates the system generation with expected loads and expected resources including power purchases from independent producers, and expected plant maintenance and fuel prices. The hourly running costs are then aggregated by time-of-use rating periods, converted to 2007 dollars, and then adjusted to include variable operations & maintenance, administrative & general loadings, revenue requirements for the incremental fuel stock and working cash, and marginal energy line losses. A summary of the estimated marginal energy costs by voltage level and by time-of-use rating period for each year from 2007 to 2011 is presented in HECO-2013.

RATE DESIGN AND PROPOSED RATES

Q. What is rate design?

A. Rate design is the conversion or translation of the Company's proposed revenue requirements for each rate class into pricing structure to collect HECO's required revenues to cover its total costs of providing service.

Q. What factors does the Company consider in designing the proposed rates?

A. HECO typically considers the following factors in developing the proposed rates:

1. production of the Company's test-year revenue requirements;
2. classes' cost of service;
3. revenue stability;
4. rate stability and rate continuity;
5. impact on customers;
6. customer choice;
7. provide fair and equitable rates;
8. simplicity, ease of understanding, and ease of implementation; and
9. encourage customer load management.

In general, changes to HECO's rates are aimed at aligning the rate elements closer to the cost components, minimizing intra-class subsidy, and moving closer to more efficient pricing that provides more accurate price signals.

Q. How did HECO develop the rate design proposed in this case?

A. HECO's proposed rate design in this case is the same as proposed in rebuttal testimony in HECO's 2005 test year case, except for specific differences in

Schedule G, Schedule H, Schedule PP, and Rider I, as discussed below. In addition, HECO proposes an inclining rate block structure in Schedule R, similar in structure to HELCO's proposal in Docket No. 05-0315. The proposed customer charges and minimum charges are the same as provided in HECO's settlement agreement with the Consumer Advocate and the Department of Defense ("DOD") in September 2005 in the test year 2005 rate case. Proposed demand charges for the commercial rate classes are designed to recover a higher percentage of demand costs than in the past, approximately 50% of demand costs in proposed Schedule J and Schedule H, and approximately 67% of demand costs in the first demand charge tier for Schedules PS, Schedule PP, and Schedule PT. The demand charge difference in the tiers at proposed rates will repeat the existing $0.50 per kWb and $1.50 per kWb differences at the existing rates. The proposed adjustments for supply voltage delivery for Schedule G, Schedule J, Schedule F, and Schedule U are based on a test year 2007 analysis performed by the Transmission Planning division. Finally, energy charges are adjusted to achieve the proposed revenue by rate class. In the case of Schedule J, Schedule PS, Schedule PP, and Schedule PT, each energy charge tier is proposed to be adjusted by approximately the same amount in cents per kWh.

Q. Are there settlement issues from the test year 2005 rate case that impact the rate design?

A. There are three settlement issues from the test year 2005 rate case that have impacted the proposed rate design: a) Schedule H rate design, b) Power Factor rate design, and c) Schedule PS, PP, PT rate design.

Q, What is the issue regarding Schedule H rate design?

A. The Consumer Advocate ("CA"), DOD and HECO agreed in settlement in the test year 2005 rate case that HECO will develop and submit a plan to freeze or cost justify Schedule H in HECO's next rate case.

Q. How does HECO proposed to address the Schedule H rate design issue?

A. HECO proposed to close Schedule H to new customers.

Q. What is the issue regarding Power Factor rate design?

A. The Consumer Advocate, DOD and HECO agreed in settlement in the test year 2005 rate case that HECO will conduct a cost study to support cost-based power factor credits or charges in HECO's next rate case.

Q. Has HECO performed such a study?

A. HECO has not completed such a study at this time. HECO's preliminary analysis of the power factor issue indicates that the cost basis for power factor is in fact complex and subject to variation depending on the needs of the HECO system to meet customer var-hr ("vars") requirements. HECO supplies vars through capacitor banks that are installed on the transmission and distribution system, and also through generation at the power plants. The amount of vars provided through generation varies with the total vars demand, with whether the capacitor banks are switched on or off, and with the maintenance of transmission and distribution lines, among other considerations. The customer demand for vars depends on both amount of load and the physical location of the load.

Q. Is the cost of providing vars captured on the HECO system?

A. Yes, the cost of providing vars is already captured in the capital and operating costs of the HECO system. The cost of distribution system and transmission system capacitors is included in the estimate of test year rate base. The cost of the var support provided through generation is included in the test year estimate of fuel expense.

Q. How can the cost of providing the vars be quantified?

A. Estimating the cost of providing vars will require a complicated system analysis, which requires the time and resources of others beyond the rate design group.

Q. Is HECO willing to continue its support of the settlement agreement on this issue?

A. Yes, HECO is still willing to complete a cost study to support cost-based power factor credits or charges. At the same time, HECO asks that the parties recognize that this is not a simple analysis and may take some time to complete, and may not be available in a timely basis for this docket. HECO proposes that the power factor adjustment clauses remain unchanged, while HECO works towards completion of this power factor cost study.

Q. What is the issue regarding Schedule PS, PP, PT rate design?

A. The Consumer Advocate, DOD and HECO agreed in settlement in the test year 2005 rate case to a kW billing credit for Schedule PP customers that are directly served by a distribution substation, and that HECO will conduct a cost study to support Schedule PS, PP, PT rate design based on service equipment and service voltages in HECO's next rate case.

Q. Did HECO complete such a study?

A. HECO has not completed such a study at this time. HECO would like to undertake such a study, but estimates it will take considerably more than a year to complete, and is unlikely to be available until HECO's next general rate case subsequent to the 2007 test year. HECO proposes to continue the dual demand charge rate design for Schedule PP, which was agreed to in the September 2005 settlement agreement, where there are separate, lower demand charges for Schedule PP customers that are directly served from distribution substations.

Q. What are the proposed changes to HECO's existing rates?

A. The proposed rate design changes to each rate schedule are summarized in the following section:

Schedule R – Residential Service

Q. What is Schedule R?

A. Schedule R is for residential electric service applicable to individually metered residential dwelling units.

Q. What are the proposed changes to Schedule R?

A. The following are the proposed changes to Schedule R:

1. increase the Customer Charge from \$7.00 to \$8.00 per month for Single-Phase Service, and from \$15.00 to \$17.00 per month for Three-Phase Service;
2. increase the Base Fuel Energy Charge from 3.5140 ¢/kWh to 10.8940 ¢/kWh;
3. change the Non-Fuel Energy Charge from 7.7814 ¢/kWh to three tiers, 8.8981 ¢/kWh for the first 350 kWh, 10.1951 ¢/kWh for the next 850 kWh, and 11.0878 ¢/kWh for all kWh over 1,200 kWh per billing period;
4. increase the Minimum Charge from \$16.00 to \$17.00 per month for Single-Phase Service and to \$22.00 per month for Three-Phase Service; and
5. change 1st paragraph of the Apartment House Collection Arrangement provision to clarify that the 10% discount applies to the total monthly bills rendered for each apartment, and to define what the total bill includes.

The proposed changes to Schedule R are designed to produce the proposed allocated class revenue requirements of $463,564,900 as shown in HECO-2016.

Q. How are the proposed increases in the customer charges determined?

A. The proposed customer charges are the levels from the Settlement Agreement of September 2005 in HECO's test year 2005 rate case, Docket No. 04-0113.

Q. How is the proposed Base Fuel Energy Charge determined?

A. The proposed Base Fuel Charge of 10.8940 ¢/kWh is based on the test year composite fuel price for base generation, base purchased power, and base cost of fuel for HECO's distributed generation units. See the calculation of the Base Fuel Energy Charge in HECO-2014.

Q. What are the merits of the proposed inclining block rate design for Non-Fuel Energy Charges?

A. The merits on an inclining block rate design include mitigation of rate impact on the smallest users of the system, pricing signals that encourage conservation, and assignment of a greater share of the cost increase to the larger users. HELCO has made a similar proposal for Schedule R in Docket No. 05-0315, its 2006 test year rate case.

Q. What are the features of the inclining block rate proposal for the proposed Non-Fuel Energy Charges?

A. The features are three tiers, one for the first 350 kWh used in the billing period, one for the next 850 kWh used in the billing period, or kWh usage between 300 kWh and 1,200 kWh, and a third tier for kWh usage above 1,200 kWh per billing period. Each tier has a different non-fuel energy charge per kWh, with the first 350 kWh having the lowest proposed non-fuel energy charge and kWh usage over 1,200 kWh having the highest proposed non-fuel energy charge.

Q. How were the sizes of the kWh tiers determined?

A. The first tier, up to 350 kWh, was set to provide the lowest energy rate for a base kWh usage level. The second tier, from 350 kWh to 1,200 kWh, was to set to capture the majority of the kWh. As shown in HECO-2015, about 27% of customer bills fall into the lowest tier, 61% of customer bills fall into the middle tier, and 12% of the customer bills fall into the highest tier. However, approximately 90% of all kWh will be billed at either the first or second tier rate. The tiers are designed so that most of the usage is covered by the first two tiers and only the very highest residential customer usage will incur the third tier energy charges.

Q. How were the Non-Fuel Energy Charges for the kWh tiers determined?

A. The guidelines used to determine the non-fuel energy charges for the kWh tiers were to collect the demand and customer costs that are not recovered by the customer and minimum charges, to target approximately a 3% to 5% increase for customers whose billing quantities fell into the first tier only, and to target approximately the class average increase, 7.1%, for customers whose billing quantities fell into the first and second tiers. An illustration of the proposed bill impacts is presented in HECO-2017 and HECO-2018. Note that the proposed rate increase for billing quantities up to 350 kWh ranges up to 4.8%, the proposed rate increase for billing quantities between 350 kWh and 1,200 kWh ranges between 3.1% and 7.4%, and the proposed rate increase for billing quantities above 1,200 kWh ranges between 7.4% and 13.8% at current effective rates.

Q. How are the proposed minimum charges of $17.00 per month for Single-Phase Service and $22.00 per month for Three-Phase Service determined?

A. The proposed minimum charges are the levels from the Settlement Agreement of

September 2005 in HECO's test year 2005 rate case, Docket No. 04-0113, except the proposed Schedule R minimum charge for single-phase service is $1.00 per month higher. Since there is an approved interim rate increase in place in Docket No. 04-0113, the effective Schedule R single-phase service minimum charge is currently about $17.00 per month. The proposed Schedule R minimum charge is designed so that minimum bill customers see no change from their current bill, rather than an effective bill decrease if the proposed minimum charge is at the same $16.00 per month level as in the settlement agreement.

Q. What is the impact of the proposed changes to Schedule R on the residential customers?

A. HECO-2017 compares the residential electric bills under the present rates and proposed rates for various consumption levels, and HECO-2018 compares the bills under current effective rates and proposed rates.

Schedule E – Electric Service for Employees

Q. What is Schedule E?

A. Schedule E is for electric residential service for Company employees and retirees, and members of the Company's Board of Directors.

Q. Are there any changes to Schedule E?

A. No. There are no proposed changes to Schedule E.

Schedule G – General Service Non-Demand

Q. What is Schedule G?

A. Schedule G is for general power service applicable to small commercial customers with loads not exceeding 5,000 kWh per month or loads less than 25 kW.

Q. What are the proposed changes to Schedule G?

A. The following are the proposed changes to Schedule G:

1. increase the Customer Charge from $20.00 to $30.00 per month for Single-Phase service, and from $45.00 to $55.00 per month for Three-Phase service;
2. increase the Energy Charge from 11.1570 ¢/kWh to 19.9393 ¢/kWh;
3. increase the Minimum Charge from $25.00 to $30.00 per month for Single-Phase service, and from $45.00 to $55.00 per month for Three-Phase service; and
4. change the Primary Supply Voltage Service from 1.9% to 2.1% for distribution primary (DP) customers, and from 0.7% to 0.5% for distribution secondary (DS) customers.

The proposed changes to Schedule G are designed to produce the proposed allocated class revenue requirements of $86,424,500 as shown in HECO-2016.

Q. How did you determine the proposed customer charge for Single-Phase and Three-Phase Service?

A. The proposed customer charges are the levels from the Settlement Agreement of September 2005 in HECO's test year 2005 rate case, Docket No. 04-0113.

Q. How are the proposed minimum charges for Single-Phase and Three-Phase service determined?

A. The proposed minimum charges are the levels from the Settlement Agreement of September 2005 in HECO's test year 2005 rate case, Docket No. 04-0113.

Q. How is the proposed Energy Charge of 19.9393 ¢/kWh determined?

A. The proposed Energy Charge of 19.9393 ¢/kWh recovers the remainder of the class' allocated revenue requirements at proposed rates that are not recovered from the proposed customer charges and minimum charges. This includes all of the class' energy costs and the remainder of the class' allocated fixed costs.

Q. How are the proposed changes to the Primary Supply Voltage adjustments determined?

A. The proposed changes to the Primary Supply Voltage adjustments are based on the system loss analysis prepared by HECO's Transmission Planning Division in this rate case, see HECO-WP-2001.

Q. In Docket 04-0113, HECO proposed to close the Schedule G primary supply voltage service to new customers. Why is HECO not repeating that proposal in this docket?

A. HECO would prefer to serve Schedule G customers at secondary voltage. However, having the option of primary voltage service allows HECO to make adjustments in service where operationally necessary, and also allows HECO to serve customers from larger commercial rate schedules (Schedule J, Schedule PS, PP, and PT) that may have reduced their energy requirements significantly but still take service above secondary voltage levels.

Q. What is the impact of the proposed changes to Schedule G customers?

A. HECO-2017 compares the commercial electric bills under the present rates and proposed rates for various consumption levels, and HECO-2018 compares the bills under current effective rates and proposed rates.

Schedule J – General Service Demand

Q. What is Schedule J?

A. Schedule J is for general power service applicable to commercial customers with loads greater than 5,000 kWh per month or at least 25 kW. The current Schedule J allows commercial customers to change service from Schedule J to any of the applicable large power service (Schedules PS, PP, or PT). The proposed modification to Schedule J's Availability Clause is to clarify the load limits for the medium-sized commercial customers that qualify for service under Schedule J.

Q. What are the proposed changes to Schedule J?

A. The following are the proposed changes to Schedule J:

1. increase the Customer Charge from \$35.00 to \$50.00 per month for Single-Phase service, and from \$60.00 to \$70.00 per month for Three-Phase service;
2. increase the Demand Charge from \$5.75 to \$12.00 per kW;
3. increase the Energy Charge for the three load factor blocks from 8.6900 ¢/kWh, 7.5419 ¢/kWh, and 6.5130 ¢/kWh to 15.7410 ¢/kWh, 14.5929 ¢/kWh, and 13.5639 ¢/kWh, respectively;
4. change the Availability Clause to clarify the current load thresholds and to add a maximum qualifying load less than 300 kW to new customers, and add a clause that would allow customers with loads equal or greater than 300 kW currently receiving service under Schedule J to remain under Schedule J;
5. change the demand ratchet in determining the billing demand under the Determination of Demand provision from the current 75% ratchet to the average demand ratchet;
6. change the Supply Voltage Delivery provision to include a Network Adjustment to apply to customers who are served at the downtown underground network system;

7. change the supply voltage adjustments in the Supply Voltage Delivery provision from 3.3 % to 2.9% for transmission primary supply voltage (TP adj.), from 1.9% to 2.1% for distribution primary supply voltage (DP adj.), and from 0.7% to 0.5% for distribution secondary supply voltage (DS adj.); and

8. include a minimum 5-year term of contract clause for new service connection and a service termination charge equal to the total connection cost incurred by the Company to connect the customer to the system less any customer advance or contribution paid by the customer.

The proposed changes to Schedule J rates are designed to produce the proposed allocated class' revenue requirements of $398,587,800 as shown in HECO-2016.

Q. How are the proposed customer charges of $50.00 and $70.00 per month for Single-Phase and Three-Phase service, respectively, determined?

A. The proposed customer charges are the levels from the Settlement Agreement of September 2005 in HECO's test year 2005 rate case, Docket No. 04-0113.

Q. How is the proposed demand charge of $12.00 per kW determined?

A. The proposed demand charge of $12.00 per kW is based on about 50% of the class's full unit demand cost. HECO continues to propose increasing the amount of demand costs recovered by demand charges, which is also a movement towards aligning rates with the cost of service.

Q. How are the proposed energy charges determined?

A. The proposed energy charges in the three load factor blocks are designed to recover all of the class's allocated energy costs as well as the remaining customer-related and demand-related costs that are not recovered in the proposed customer and demand charges. The proposed energy charges are approximately the same rate increase in cents per kWh in each energy charge block.

Q. Why is the Company proposing a maximum qualifying load of less than 300 kW for Schedule J?

A. HECO made this proposal in the test year 2005 rate case, and the CA and DOD did not object to this provision in the settlement agreement. HECO's proposal to define a maximum qualifying load under Schedule J is based on the following reasons:

1. to better define and clarify the load size that qualifies under Schedule J for ease of understanding and application;
2. to make a clearer distinction between the medium-sized customers served under Schedule J, and the large power customers served under the Schedules PS, PP, or PT;
3. to apply Schedule J to a more homogenous group of medium-size commercial and industrial customers with similar load levels and characteristics, essential for designing more efficient pricing and costing, and facilitate aligning rates closer to cost of service; and
4. for rate and revenue stability and continuity.

Q. Will customers currently served under Schedule J with loads equal to or greater than 300 kW be allowed to stay on Schedule J?

R. Yes. These customers will be grandfathered and can remain to be served under Schedule J, if they chose. The new proposed maximum qualifying load under Schedule J will apply to new customers.

Q. Why is HECO proposing to change Schedule J's demand ratchet?

A. HECO is proposing to change Schedule J's demand ratchet for determining the billing kW from the current 75% ratchet to average demand ratchet for simplicity and ease of understanding. The proposed average demand ratchet is the same as the current demand ratchet in Schedules PS, PP, and PT, making the demand ratchet provisions for all the demand rate schedules the same and consistent. The average demand ratchet compares the customer's maximum demand for the current billing period with the average of his current maximum demand and his maximum demand for the last 11 months, as well as with Schedule J's minimum billing demand of 25 kW – in determining the customer's billing kW demand. The customer's demand charge is based on the highest of these three demand values.

Q. What is the basis for adding the proposed Network Adjustment in the Schedule J's Supply Voltage Delivery provision?

A. The proposed Network Adjustment of +0.9% applied to the demand and energy charges is the same as the Network Adjustment currently in-effect for Schedule PS. This adjustment is applied to customers who are served in the downtown network system also known as the Iwilei Network. This network system serves both the Honolulu downtown financial district and the Chinatown area. The network is considered to be the most reliable system on the HECO electrical grid, due to the multiple redundancies of the circuits on both the primary and secondary voltage levels.

Q. How did you determine the proposed changes to the supply voltage adjustments?

A. The determination of the proposed changes to the supply voltage adjustments for transmission primary supply voltage, distribution primary supply voltage, and distribution secondary supply voltage are based on the system loss analysis prepared by HECO's Transmission Planning Division in this rate case, see

HECO-WP-2001.

Q. Why is HECO proposing to include a term of contract clause in Schedule J?

A. HECO made this proposal in the 2005 test year. HECO is proposing a 5-year term of contract for new service connections under Schedule J to allow HECO to recover its costs of connecting new services or customers to the system from those customers rather than shifting such costs to other ratepayers, and to make it consistent with the provisions of HECO's Rule 13 relating to the determination of the customer advance required from the customer.

Q. What is the impact of the proposed changes to Schedule J customers?

A. HECO-2017 compares the commercial electric bills under the present rates and proposed rates for various consumption levels, and HECO-2018 compares the bills under current effective rates and proposed rates.

<u>Schedule H – Commercial Cooking, Heating, Air Conditioning, and Refrigeration Service</u>

Q. What is Schedule H?

A. Schedule H is an end-use rate that applies to specific commercial electric loads including commercial cooking, heating, air conditioning, and refrigeration loads that are less than 600 volts.

Q. What are the proposed changes to Schedule H?

A. The following are the proposed changes to Schedule H:

1. increase the Customer Charge from $20.00 to $25.00 per month for Single-Phase service, and from $45.00 to $60.00 per month for Three-Phase service;
2. increase the Demand Charge from $9.00 per kWb to $10.00 per kWb;
3. increase the Energy Charge from 7.7422 ¢/kWh to 16.5324 ¢/kWh; and

4. close the rate schedule to new customers.

The proposed changes to Schedule H are designed to produce the class's total allocated revenue requirements of $7,873,700 as shown in HECO-2016.

Q. How are the proposed customer charge of $25.00 per month for Single-Phase service and $60.00 per month for Three-Phase service determined?

A. The proposed customer charges are the levels from the Settlement Agreement of September 2005 in HECO's test year 2005 rate case, Docket No. 04-0113.

Q. How is the proposed demand charge of $10.00 per kW determined?

A. The proposed demand charge of $10.00 per kW is based on about 50% of the class's full unit demand cost. HECO continues to propose increasing the amount of demand costs recovered by demand charges, which is also a movement towards aligning rates with the cost of service.

Q. How did you determine the proposed energy charge?

A. The proposed energy charge is based on recovering the class's total allocated energy-related and demand-related costs as well as the remaining customer-related costs that are not recovered from the proposed customer charge.

Q. Why is HECO proposing to close Schedule H to new customers?

A. In accordance with the settlement agreement reached in Docket No. 04-0113 in September 2005, HECO proposes to freeze Schedule H.

Q. How will that impact existing Schedule H customers?

A. The Company proposes that there will be no new Schedule H service connections, with the exception of allowing customers with existing Schedule H service to relocate their Schedule H service. That is, a customer who terminates Schedule H service in one location will be allowed to contemporaneously open a new Schedule H service in another service location. There is no net gain of Schedule

H customers in this situation.

Q. What is the impact of the proposed changes to Schedule H customers?

A. HECO-2017 compares the commercial electric bills under the present rates and proposed rates for various consumption levels, and HECO-2018 compares the bills under current effective rates and proposed rates.

<u>Schedule PS – Large Power Secondary Voltage Service</u>

Q. What is Schedule PS?

A. Schedule PS is for general power service applicable to commercial or industrial customers with large power loads of at least 300 kW that are served at the secondary voltage level.

Q. What are the proposed changes to Schedule PS?

A. The following are the proposed changes to Schedule PS:

1. increase the Customer Charge from $320.00 to $350.00 per month;
2. increase the Demand Charge for the three demand blocks from $10.00 per kW, $9.50 per kW, and $8.50 per kW to $20.00, $19.50, and $18.50 per kW, respectively;
3. increase the Energy Charge for the three load factor blocks from 7.2087 ¢/kWh, 6.4104 ¢/kWh, and 6.1010 ¢/kWh, to 14.1560 ¢/kWh, 13.3577 ¢/kWh, and 13.0485 ¢/kWh, respectively;
4. eliminate the 150 kW minimum power service under the Minimum Billing provision; and
5. change the Term of Contract provision for new service connections from one year to five years in order to be consistent with HECO's Rule 13 provision on the determination of the customer advance required from

customers, and add a service termination charge equal to the total connection cost incurred by the Company to connect to customer to the system less any customer advance or contribution paid by the customer. This proposal was advanced by the Company in the last rate case. The proposed changes to Schedule PS rates are designed to produce the proposed allocated class' revenue requirements of $150,691,100 as shown in HECO-2016.

Q. Please explain how the proposed customer charge was determined?

A. The proposed customer charge is the level from the Settlement Agreement of September 2005 in HECO's test year 2005 rate case, Docket No. 04-0113.

Q. Please explain how you determined the proposed demand charges?

A. The proposed demand charge for the first demand block is designed to recover approximately 67% of the class's total demand-related costs. HECO continues to propose increasing the amount of demand costs recovered by demand charges, which is also a movement towards aligning rates with the cost of service. The proposed demand charges for the 2nd and 3rd demand blocks were set to maintain the rate differentials between the demand blocks reflected in the present rates for rate continuity and stability.

Q. How are the proposed energy charges determined?

A. The proposed energy charges are based on recovering the class's proposed allocated total revenue requirements less the revenues recovered from the proposed customer and demand charges. This includes the entire energy-related costs (or variable costs) and the remainder of the customer-related costs and the demand-related costs (or fixed costs) that are not recovered from the proposed customer and demand charges. The proposed energy rates for each energy block have approximately the same cents per kWh increase over the current Schedule PS energy block rates.

Q. Why is HECO proposing to eliminate the 150 kW minimum power service?

A. The 150 kW minimum power service was closed to new customers after January 1, 1986 - over 20-years ago. There are no customers in Schedule PS that have the 150 kW of minimum billing demand.

Q. What is the impact of the proposed changes to Schedule PS customers?

A. HECO-2017 compares the commercial electric bills under the present rates and proposed rates for various consumption levels, and HECO-2018 compares the bills under current effective rates and proposed rates.

<u>Schedule PP – Large Power Primary Voltage Service</u>

Q. What is Schedule PP?

A. Schedule PP is for general power service applicable to commercial or industrial customers with large power loads of at least 300 kW served at primary voltage.

Q. What are the proposed changes to Schedule PP?

A. The following are the proposed changes to Schedule PP:

1. increase the Customer Charge from $320.00 to $400.00 per month;
2. increase the Demand Charge for the three demand blocks from $9.81 per kW, $9.32 per kW, and $8.34 per kW to $18.50, $18.00, and $17.00 per kW, respectively;
3. provide for a billing credit of $1.75 per kW for Schedule PP customers who are directly served from distribution substations;
4. increase the Energy Charge for the three load factor blocks from 7.0715 ¢/kWh, 6.2884 ¢/kWh, and 5.9849 ¢/kWh, to 14.5773 ¢/kWh,

13.7944 ¢/kWh, and 13.4907 ¢/kWh, respectively;

5. change the Secondary Metering Adjustment from the current 0.1081 ¢/kWh to 0.2825 ¢/kWh;
6. eliminate the 150 kW minimum power service under the Minimum Billing provision, for the same reasons indicated for Schedule PS; and
7. change the Term of Contract provision for new service connections from one year to five years in order to be consistent with HECO's Rule 13 provision on the determination of the customer advance required from customers, and add a service termination charge equal to the total connection cost incurred by the Company to connect the customer to the system less any customer advance or contribution paid by the customer. This proposal was made by the Company in the 2005 test year rate case.

The proposed changes to Schedule PP rates are designed to produce the proposed allocated class' revenue requirements of $354,407,500 as shown in HECO-2016.

Q. Please explain how the proposed customer charge was determined.

A. The proposed customer charge is the level from the Settlement Agreement of September 2005 in HECO's test year 2005 rate case, Docket No. 04-0113.

Q. Please explain how the proposed demand charges were determined.

A. The proposed demand charge for the first demand block is designed to recover approximately 67% of the class's total demand-related costs. HECO continues to propose increasing the amount of demand costs recovered by demand charges, which is also a movement towards aligning rates with the cost of service. The proposed demand charges for the 2nd and 3rd demand blocks were set to maintain the rate differentials between the demand blocks reflected in the present rates for rate continuity and stability.

Q. What is the basis for the billing credit per kW proposed for Schedule PP customers that are directly served from distribution substations?

A. HECO agreed in settlement in the test year 2005 rate case to a kW billing credit for Schedule PP customers that are directly served by a distribution substation. HECO also agreed to conduct a cost study to support Schedule PS, PP, PT rate design based on service equipment and service voltages in HECO's next rate case. HECO has not completed such a study at this time. HECO would like to undertake such a study, but estimates it will take considerably more than a year to complete, and is unlikely to be available until HECO's next general rate case subsequent to the 2007 test year. HECO proposes to embed the dual demand charge rate design for Schedule PP, where there are separate, lower demand charges for Schedule PP customers that are directly served from distribution substations.

Q. How are the proposed energy rates determined?

A. Like Schedule J and Schedule PS, the proposed energy rates are determined to recover the remainder of the class' allocated revenue requirements at proposed rates that are not recovered in the proposed customer and demand charges. This includes the class's entire energy cost and the remainder of the customer and demand costs that are not recovered in the proposed customer and demand charges. The proposed energy rates for each energy block have approximately the same cents per kWh increase over the current Schedule PP energy block rates.

Q. How is the proposed Secondary Metering Adjustment determined?

A. The Secondary Meter Adjustment reflects the transformer losses applied to customers whose metering point is situated on the customer side of the meter (distribution secondary or DS customers), and is based on the system loss analysis. The estimated secondary metering revenue adjustment of $60,800 was translated to a usage charge of 0.2825 ¢/kWh on the basis of the estimated test-year kWh usage of the DS customers as shown in HECO-WP-2016.

Q. What is the impact of the proposed changes to Schedule PP customers?

A. HECO-2017 compares the commercial electric bills under the present rates and proposed rates for various consumption levels, and HECO-2018 compares the bills under current effective rates and proposed rates.

Schedule PT – Large Power Transmission Voltage Service

Q. What is Schedule PT?

A. Schedule PT is for general power service applicable to commercial or industrial customers with large power loads of at least 300 kW served at transmission voltage level.

Q. What are the proposed changes to Schedule PT?

A. The following are the proposed changes to Schedule PT:

1. increase the Customer Charge from $320.00 to $400.00 per month;
2. increase the Demand Charge for the three demand blocks from $9.67 per kW, $9.19 per kW, and $8.22 per kW to $16.25, $15.75, and $14.75 per kW, respectively;
3. increase the Energy Charge for the three load factor blocks from 6.9708 ¢/kWh, 6.1989 ¢/kWh, and 5.8997 ¢/kWh, to 14.3519 ¢/kWh, 13.5799 ¢/kWh, and 13.2809 ¢/kWh, respectively;
4. change the Secondary Metering Adjustment from the current 0.0865 ¢/kWh to 0.5% adjustment to the demand and energy charges;
5. eliminate the 150 kW minimum power service under the Minimum

Billing provision, for the same reasons indicated for Schedule PS; and

6. change the Term of Contract provision for new service connections from one year to five years in order to be consistent with HECO's Rule 13 provision on the determination of the customer advance required from customers, and add a service termination charge equal to the total connection cost incurred by the Company to connect the customer to the system less any customer advance and/or contribution paid by the customer. This proposal was made by the Company in the 2005 test year rate case.

The proposed changes to Schedule PT rates are designed to produce the proposed allocated class' revenue requirements of $27,887,500 as shown in HECO-2016.

Q. Please explain how the proposed customer charge was determined?

A. The proposed customer charge is the level from the Settlement Agreement of September 2005 in HECO's test year 2005 rate case, Docket No. 04-0113.

Q. Please explain how the proposed demand charges were determined.

A. The proposed demand charge of $16.25 per kW for the 1st demand block is based on approximately 67% of the class's full unit demand cost. HECO continues to propose increasing the amount of demand costs recovered by demand charges, which is also a movement towards aligning rates with the cost of service. The proposed demand charges for the 2nd and 3rd demand blocks were set to maintain the rate differentials between the demand blocks reflected in the present rates for rate continuity and stability.

Q. How are the proposed energy rates determined?

A. Like Schedule PS and Schedule PP, the proposed energy rates are determined to recover the remainder of the class' allocated revenue requirements at proposed rates that are not recovered in the proposed customer and demand charges. This includes the class's entire energy cost and the remainder of the customer and demand costs that are not recovered in the proposed customer and demand charges. The proposed energy rates for each energy block have approximately the same cents per kWh increase over the current Schedule PT energy block rates.

Q. How is the proposed change to the Secondary Metering Adjustment determined?

A. As in Schedule PP, the Secondary Meter Adjustment reflects the transformer losses applied to customers whose metering point is situated on the customer side of the meter (transmission secondary or TS customers), and is based on the system loss analysis for this rate case. Since HECO currently does not have customers receiving service at transmission secondary, rather than reflecting an estimated revenue adjustment for this service which is then translated into a ¢/kWh adjustment, HECO is proposing to change the adjustment to 0.5% applied to demand and energy charges of customers who receive service at transmission voltage and who elect to be metered at the secondary side of his transformer.

Q. How did you determine the proposed 0.5% adjustment?

A. The determination of the proposed 0.5% adjustment is based on the same system loss analysis prepared by the Transmission Planning Division for this case.

Q. What is the impact of the proposed changes on Schedule PT customers?

A. HECO-2017 compares the commercial electric bills under the present rates and proposed rates for various consumption levels, and HECO-2018 compares the bills under current effective rates and proposed rates.

Schedule F – Public Street Lighting, Highway Lighting, and
Park and Playground Floodlighting Service

Q. What is Schedule F?

A. Schedule F is for public street and highway lighting and for parks and playground floodlighting.

Q. What are the proposed changes to Schedule F?

A. The following are the proposed changes to Schedule F:

1. add a Customer Charge of $20.00 per month;
2. increase the energy charge for the two load factor blocks from the current 12.7049 ¢/kWh and 8.7309 ¢/kWh to 22.0105 ¢/kWh and 18.0368 ¢/kWh, respectively;
3. change the secondary metering adjustment under the Optional Secondary Metering for Street and Highway Lighting provision from the current 2.0% to 1.5%, and clarify the "monthly bill" basis of the adjustment; and
4. change the loss factor of 1.05 used in the determination of the billing demand for unmetered service to 1.02 loss factor, under the Special Terms and Conditions provision.

The proposed changes to Schedule F rates are designed to produce the proposed allocated class' revenue requirements of $7,628,800, as shown in HECO-2016.

Q. How did you determine the proposed Customer Charge of $20.00 per month?

A. The proposed Customer Charge of $20.00 per month is based on recovering approximately 60% of the class's full customer-related cost.

Q. Please explain how you derived the proposed energy charges for the two load factor blocks?

A. Like Schedule R and Schedule G, the proposed energy rates for Schedule F are determined to recover the remainder of the class' allocated revenue requirements at proposed rates that are not recovered in the proposed customer and minimum charges. This includes the class's entire energy cost and the remainder of the customer and demand costs that are not recovered in the proposed customer and minimum charges. The proposed energy rates for each energy block have approximately the same cents per kWh increase over the current Schedule F energy block rates.

Q. How is the proposed secondary metering adjustment of 1.5% and the proposed loss factor of 1.02 for the unmetered service determined?

A. The determination of the proposed secondary metering adjustment of 1.5% and the loss factor of 1.02 for unmetered service are based on the system loss analysis prepared by the Transmission Planning Division for the test year 2007 as shown in HECO-WP-2001.

Q. What is the impact of the proposed changes to Schedule F customers?

A. HECO-2017 compares the commercial electric bills under the present rates and proposed rates for various consumption levels, and HECO-2018 compares the bills under current effective rates and proposed rates.

<u>Schedule U – Time-of-Use Service</u>

Q. What is Schedule U?

A. Schedule U is an optional Time-of-Use Service for commercial or industrial customers with large power loads of at least 300 kW. Large power customers who are served under any of the large power rates (Schedule PS, Schedule PP, and Schedule PT) may chose to be served under Schedule U.

Schedule U provides an on-peak demand charge and time-differentiated energy rates. For instance, the demand charge is applied only to kW load used during the on-peak period, and the energy rates are differentiated by the time-of-use rating periods. Service under Schedule U is based on customer selection.

Q. What are the proposed changes to Schedule U?

A. The proposed changes to Schedule U include the following:

1. increase the Customer Charge from \$215.00 to \$350.00 per month;
2. increase the Demand Charge from \$17.00 to \$22.50 per kW if the customer's maximum demand occurs during the priority peak period and \$19.50 per kW is the customer's maximum demand occurs during the mid-peak period;
3. increase the Energy Charge from the current 7.8230 ¢/kWh for on-peak period to 15.6596 ¢/kWh, and from 3.0000 ¢/kWh for off-peak period to 12.0000 ¢/kWh; and
4. change the service voltage adjustments in the Supply Voltage Delivery provision from the current 3.3%, 1.9%, and 0.7% for transmission primary, distribution primary, and distribution secondary, to 2.9 %, 2.1 %, and 0.5 %, respectively.

Q. Please explain how you determine the proposed Customer Charge of \$350.00 per month.

A. The proposed customer charge is the level from the Settlement Agreement of September 2005 in HECO's test year 2005 rate case, Docket No. 04-0113.

Q. Please explain how the proposed Demand Charges were determined.

A. The proposed demand charges were determined in the same manner as they were proposed in rebuttal testimony in HECO's test year 2005 rate case in Docket No. 04-0113. The proposed demand charge if the customer peak is during the priority peak period is based on about 75% of the Schedule PS full unit demand cost. The proposed demand charge if the customer peak is during the mid-peak period is based on the estimated average revenue per kW of the proposed Schedule PS demand charges. This makes the structure of the proposed demand charge consistent with the proposed Schedule TOU-C option for customers who are served on Schedule J.

Q. How did you determine the proposed time-of-use energy rates for Schedule U?

A. The proposed On-Peak Energy Rate of 15.6596 ¢/kWh is based on the proposed average energy charge for Schedule PS increased by 2.0 ¢/kWh, which is the same derivation used in rebuttal testimony in HECO's test year 2005 rate case in Docket No. 04-0113. The proposed Off-Peak Energy Rate of 12.000 ¢/kWh is based on the unit energy cost for Schedule PS.

Q. How did you determine the proposed changes to the service voltage adjustments under the Supply Voltage Delivery provision?

A. The proposed changes to the service voltage adjustments are the same as proposed for Schedule J, and discussed above.

Q. Are there changes to the time-of-use rating periods for Schedule U.

A. No. The time-of-use rating periods remain the same as those used in the current Schedule U.

<u>Rider T – Time-of-Day Rider</u>

Q. What is Rider T?

A. Rider T is an optional time-of-use service rider for commercial or industrial customers with power loads of at least 25 kW who are served under Schedule J, or Schedule PS, or Schedule PP, or Schedule PT. Rider T modifies or provides adjustments to the applicable rate schedule's demand and energy rates, which effectively results in time-of-use price signals. Like the other load management Riders M and I, Rider T was approved by the Commission in Docket No. 2793, and was first implemented in 1981. It was aimed at encouraging customers to manage their loads in order to help reduce the system peak load and defer the need for the next capacity addition.

Q. Is HECO proposing any changes to the Rider T?

A. Yes. HECO is proposing the following changes to Rider T:

1. change the Rider T's Availability Clause to appropriately reference the three separate Schedules PS, PP, and PT, as well as the new Schedule TOU-C; and
2. add terms and conditions that would allow customers to do emergency maintenance on their generating equipment, if any, without considering its impact on the customers' maximum on-peak demand in the determination of their billing demand.

Rider M – Off-Peak and Curtailable Service

Q. What is Rider M?

A. Rider M is an optional off-peak and Curtailable service applicable to Schedule J customers with loads greater than 100 kW, and to customers served under Schedule PS, Schedule PP, or Schedule PT, with loads greater than 300 kW. Rider M provides load management incentives to customers by modifying the determination of the billing demand under Schedules J, PS, PP, or PT. It offers two load management service options: Option A – Off-Peak Service, and Option B – Curtailable Service.

The Rider M – Off-Peak Service (Option A) encourages customers to shift their load to the off-peak hours by basing the determination of the billing demand only on the customers' kW demand during the on-peak period. The Rider M – Curtailable Service (Option B) encourages customers to shift their load to off-peak hours by reducing the customers' billing demand by 75% of the kW load that they curtail during the Company's priority peak period, or by 40% of the kW load that they curtail for a two-hour duration specified by the Company.

Q. Is HECO proposing any changes to Rider M?

A. Yes. The following are the proposed changes to Rider M:

1. modify the Availability Clause to appropriately reference the three separate Schedules PS, PP, and PT, and the new Schedule TOU-C; and
2. change the initial Term of Contract from three years to five years, consistent with the proposed change for the other rate schedules.

Rider I – Interruptible Contract Service

Q. What is Rider I?

A. Rider I is an optional interruptible service available to large power customers with interruptible kW load of at least 500 kW.

Q. Did HECO propose any changes to Rider I in Docket No. 04-0113?

A. Yes, HECO proposed to reduce the minimum qualifying interruptible load from the current minimum of 500 kW to 100 kW in order to extend the availability of Rider I to smaller customers, and expand its potential customer base.

Q. Does HECO make the same proposal in this case?

A. No. Rather, HECO proposes to close the existing Rider I to new customers. HECO's Commercial and Industrial Direct Load Control ("CIDLC") program is expected to provide customers with an interruptible service opportunity that is broader than the existing Rider I. As indicated by Mr. Hee in HECO T-9, CIDLC program modifications are planned for filing by the end of 2006 that will increase customer incentive levels, reduce the minimum interruptible load required for program participation, provide a non-underfrequency relay option, provide a voluntary load control feature, and provide a small business load control feature. These enhancements to the CIDLC program provide tools for HECO to focus on expansion of interruptible service to customers, and therefore also allow for closing of the existing Rider I.

<u>Schedule Q – Purchases from Qualifying Facilities 100 kW or Less</u>

Q. What is Schedule Q?

A. Schedule Q applies to customers with small power production facilities with design capacity of 100 kW or less, qualifying under Chapter 74, Title 6 of the PUC Rules, and who have a purchased power contract with the Company. Schedule Q provides the energy rates and energy cost adjustment that the Company pays for energy purchased by the Company from the customer, and the metering charge to the customer for metering, billing and administration of the purchase power contract.

Q. Are there proposed changes to Schedule Q?

A. Yes. The following are the proposed changes to Schedule Q:

1. change the Energy Rates for energy delivered to the Company by the customer from the current 3.67 ¢/kWh to 12.94 ¢/kWh;
2. change the Metering Charge to a Service Charge of $20.00 per month for both Single-Phase and Three-Phase Service; and

3. change the generation base fuel cost from the current 287.83 ¢/mbtu to 1,063.14 ¢/mbtu.

Q. How was the proposed energy rate of 12.94 ¢/kWH for energy delivered to HECO determined?

A. The proposed energy rate of 12.94 ¢/kWh for energy delivered by the customer to HECO is based on the test year estimates of the Company's generation cost and Distributed Generation cost and efficiency factors discussed in HECO T-4.

Q. Please explain how you determine the proposed Service Charge?

A. The proposed Service Charge of $20.00 per month reflects the billing and administration cost of the purchased power delivered by the customer to the Company. It is based on the customer accounting and customer services expense for Schedule J. This proposed Service Charge will apply to Schedule Q customers who also buy power from HECO under the applicable rate schedule. The Schedule Q customers who only deliver or sell power to HECO and who do not buy power from HECO will be charged the Customer Charge in Schedule J in lieu of this Service Charge, which also reflects the metering cost and the meter reading costs.

Q. What is the basis of the changes to Schedule Q's Energy Cost Adjustment Clause?

A. The proposed 1,063.14 ¢/mbtu in Schedule Q's Energy Cost Adjustment Clause is based on the test-year estimate of the total composite generation cost including Distributed Generation costs and discussed in HECO T-9. The test-year fuel price and efficiency factors used to determine this composite generation cost are discussed in HECO T-4.

<u>Energy Cost Adjustment Clause</u>

Q. What is the Energy Cost Adjustment Clause?

A. The Energy Cost Adjustment Clause (ECAC) is a reconciliation mechanism that allows the Company to recover or refund the difference between the fuel price embedded in the base rates and the fuel price that it actually pays.

Q. What are the proposed changes to ECAC?

A. The following are the proposed changes to ECAC:

1. modify the ECAC's Applicability Clause for clarity and to identify the three separate Schedules PS, PP, PT, as well as the new Schedule TOU-R, Schedule TOU-C;
2. change the base fuel cost for Company generation from the current 287.83 ¢/mbtu to 1,059.86 ¢/mbtu Company composite cost of generation from central station and other generation;
3. change the Company generation efficiency factor from the current 0.011170 mmbtu/kWh to use three separate efficiency factors, 0.011139 mmbtu/kWh for low sulfur fuel oil (LSFO), 0.032003 mmbtu/kWh for diesel fuel, and 0.011225 mmbtu/kWh for other company generation sources;
4. add a distributed generation (DG) energy component in the Clause at 18.114 cents per kWh, adjusted to the sales delivery level and for revenue taxes; and
5. change the base purchased energy cost from the current 3.005 ¢/kWh to 6.772 ¢/kWh.

Q. How are the proposed changes to the above ECAC parameters determined?

A. The proposed changes to the base fuel costs, generation efficiency factors, DG energy component, and base purchased energy cost are discussed in HECO T-9. The ECAC calculations are presented in HECO T-9.

<u>Integrated Resource Planning Cost Recovery Provision</u>

Q. What is the Integrated Resource Planning Cost Recovery Provision ("IRP Clause")?

A. The IRP Clause is a cost recovery mechanism for the incremental costs incurred by the Company related to incremental IRP-related activities, and the recovery of the incremental DSM costs which include program costs (excluding base labor), lost margin and shareholder incentives.

Q. Does the Company still require an IRP clause?

A. Yes. The Company will have to retain the IRP clause for use in reconciling the recovery of the 1995-2005 IRP costs that HECO already recovered per stipulated agreement with the Consumer Advocate subject to refund with interest, with the amounts of such costs that the PUC would ultimately find reasonable and allow HECO to recover. Additionally, HECO will also use the current IRP clause to recover the current incremental DSM program costs, including lost margin and shareholder incentives, incurred by the Company, until a final decision is rendered in the Energy Efficiency docket.

Q. Is HECO proposing a DSM Reconciliation Clause?

A. Yes. HECO is proposing a separate DSM Reconciliation Clause in order to reconcile actual DSM incentives paid with incentives included in base rates, and to allow only the actual utility incentive earned to be recovered, as discussed in HECO T-9.

Green Pricing Program Provision

Q. What is the Green Pricing Program Provision?

A. The Green Pricing Program Provision is a voluntary fund-raising program that is open to Island residents and non-residents for purposes of funding the development of renewable energy facilities on the Island. The voluntary contributions received from this Green Pricing Program have been used for such programs as the Sun Power for Schools Pilot Program which funds the installation of photovoltaic systems in public schools.

Q. Are there changes proposed to the Green Pricing Program?

A. No. There are no changes proposed to the Green Pricing Program.

Service-Related Charges and Proposed Rule Changes

Q. What are service-related charges?

A. In addition to the rate schedules and riders, there are service-related charges included in the Company's Rules that are charged directly to the customers who caused the costs to be incurred by the utility. These service-related direct charges include the Returned Checks Charge, Field Collection Charge, and Service Establishment Charge specified in the Company's Rule 7, Sections C, D, and E, respectively, and the Late Payment Charge in Rule 8, Section D.

Q. Are there any changes to these charges?

A. Yes. The Company is proposing the following changes:

1. change the Returned Checks Charge to a Returned Payment Charge and increase the current charge from the current $7.50 to $22.00 per returned check or returned payment;

2. increase the Field Collection Charge from $15.00 to $20.00 per field collection call, and modify its application such that, the customer will be charged the Field Collection Charge even when a field call does not result in successful collection of monies; and
3. increase the Service Establishment Charge from $15.00 to $20.00, and increase the additional charge for the same day service or for service outside of the normal business hours from the current $10.00 to $25.00.

Proposed revisions to these charges were introduced in direct testimony in HECO's 2005 test year rate case, Docket No. 04-0113. The proposals presented here are identical, except that the proposed Returned Payment Charge is increased from a proposed $16.00 to a proposed $22.00 per returned payment based on more current bank charges.

Q. Why is the Company proposing to change the "Returned Checks Charge" to "Returned Payment Charge"?

A. The Company is proposing to change the "Returned Checks Charge" to "Returned Payment Charge" to reflect the different payment options that are now available to customers, and to allow the Company to apply the same service charge on "returned" payments made through any of these options.

Q. What payment options are now available to the customers?

A. In the past, customers could pay their electric bill either by check or in cash. With the changes in technology, HECO started offering customers with different electronic bill payment options of paying their electric bills ("e-billing"). The various e-billing options that are available to HECO customers include the following:

1. Automatic Bill Payment (ABP) – automatically debits customer's savings

or checking account;

2. Payment using credit card, and
3. Payment using debit card.

When payments made through any of these "paperless" payment options are "returned" due to insufficient funds in the customers' accounts, the bank charges HECO a service charge for the processing cost – similar to a bounced check processing fee. For fairness and equity, HECO is proposing to change the Returned Checks Charge to Returned Payment Charge and to apply it to any "returned" payment from any of the "paperless" payments in addition to returned checks. The proposed change will charge the cost of such returned payments to those customers who cause such costs to be incurred by HECO, rather than shifting those costs to the other ratepayers.

Q. How did you determine the proposed Returned Payment Charge of $22.00 per returned payment?

A. The proposed Returned Payment Charge of $22.00 per returned payment is based on the 2003-2004 recorded costs of processing returned payments. It reflects the labor processing costs as well as the non-labor costs including bank charges at estimated 2005 levels.

Q. Please explain how the proposed changes to the Field Collection Charge and Service Establishment Charge were determined.

A. The proposed Field Collection Charge and Service Establishment Charge are based on the costs of various activities required for these services. For instance, the cost of a field collection call includes the cost of the collection effort by a Field Representative (such as review and analysis of the customer's account, contacting the customer, mailing costs, travel costs, arranging and processing payments or disconnecting service, resolving complaints, dispatching orders, issuing service requests for repairs, and the cost of the information system support and maintenance of field service systems. The cost of service establishment reflects the cost of similar activities such as the cost of reconnecting customers including travel time, receiving customer inquiry, explaining and negotiating required payment, updating customer accounts in the billing system, issuing and dispatching orders, and information system support cost.

Q. Please explain how the Field Collection Charge is currently applied.

A. HECO's current Field Collection Charge is applied only when a field call results in actual collection of payment from the customer.

Q. What change is HECO proposing in regard to the application of the Field Collection Charge?

A. HECO is proposing to apply the proposed Field Collection Charge to every field collection call made regardless of whether a field collection call results in successful collection of payment from customer. The Company incurs the same costs as discussed above for every field collection call made regardless of whether or not it results in successful collection of payment from the customer. HECO has a Field Collection procedure in place, which ensures that a field call is made only as a last resort or attempt to collect payment from the customer.

Q. Are there other changes to HECO's Rules?

A. Yes. HECO's Rule 4, Section D, currently provides a Standard Customer Retention Rate. There are no customers on Oahu who are currently served under this rate. HECO has an increasing need for new generation capacity and/or measures to mitigate customer load growth as discussed by Mr. Alm in HECO T-1 and Mr. Sakuda in HECO T-4 in HECO's test year 2005 rate case, Docket No.

04-0113. Given HECO's current situation, HECO is proposing to discontinue the Standard Form Customer Retention Rates provided in Rule 4, Section D.

Q. Is HECO proposing to terminate any existing rate schedule or rate adjustment?

A. Yes. HECO is proposing to withdraw the Rider EV-R – Residential Electric Vehicle Charging Service, Rider EV-C – Commercial Electric Vehicle Charging Service. HECO is also terminating the temporary Rate Adjustment that became effective on July 1, 2003 for the reduction in the capacity payments to AES Hawaii. This reduction in capacity payments is reflected in the test year estimates of purchased power expense and embedded in the new proposed rate changes.

Q. Why is HECO proposing to withdraw Riders EV-R and EV-C?

A. HECO's Rider EV-R and Rider EV-C became effective on July 6, 1998. On August 13, 1998, the Company agreed to defer implementation of the riders per the Commission's request in an August 3, 1998 letter. HECO has not received PUC approval to implement these riders, although they remained in HECO's current effective rates.

More importantly, HECO's proposed Schedule TOU-R – Residential Time-of-Use Service, and Schedule TOU-C – Commercial Time-of-Use Service which are discussed later in my testimony will also apply to electric vehicle charging service. These proposed new Schedules TOU-R and TOU-C will provide time-of-use service to electric vehicle charging without the need to separately meter these loads from the rest of the customers' electric loads, as required under the Rider EV-R and Rider EV-C which were available only for the electric vehicle charging load.

NEW RATE SCHEDULES

Q. Is HECO proposing any new rate schedules and/or riders?

A. Yes. HECO is proposing the following new rate schedules:

1. Schedule TOU-R – Residential Time-of-Use Service;
2. Schedule TOU-C – Commercial Time-of-Use Service;
3. Schedule SS – Standby Service.

Schedule TOU-R and Schedule TOU-C have been proposed in HECO's test year 2005 rate case in Docket No. 04-0113. The proposed rate design here is similar in structure to those proposals advanced in the previous case. The proposed Schedule TOU-R is modified for the tiered rate structure in Schedule R. The Schedule SS was proposed in response to Decision and Order No. 22248, issued January 27, 2006, in Docket No. 03-0371, and is before the Commission for approval. The following section describes each of these new proposed rate schedules.

Schedule TOU-R – Residential Time-of-Use Service

Q. Please describe HECO's proposed Schedule TOU-R.

A. Schedule TOU-R is a standard optional residential time-of-use service offering. This new service is proposed to be implemented on a phased-in basis until HECO's new Customer Information System (CIS) is implemented since the current ACCESS billing system cannot bill time-of-use rates.

Q. What are the proposed rates for the Schedule TOU-R program?

A. The proposed rates for Schedule TOU-R pilot program are the following:

1. Customer Charge: $9.50 per month for Single-Phase Service, and

$17.50 per month for Three-Phase service;

2. Energy Charge: Calculated in the same manner and at the same rates as the proposed Schedule R, with the following time-of-use energy rate adjustments:

Priority Peak Period kWh use	+ 5.0 ¢/kWh,
Mid-Peak Period kWh use	+ 2.0 ¢/kWh, and
Off-Peak Period kWh use	– 3.5 ¢/kWh;

3. Minimum Charge is $17.50 per month for Single-Phase Service, and $22.50 for Three-Phase Service;

4. Time-of-use rating periods are

Priority Peak Period:	5:00 p.m. – 9:00 p.m., Monday – Friday
Mid-Peak Period:	7:00 a.m. – 5:00 p.m., Monday – Friday 5:00 p.m. – 9:00 p.m., Saturday – Sunday and holidays observed by both Federal and State (New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas Day)
Off-Peak Period:	9:00 p.m. – 7 a.m., Daily 7:00 a.m. – 5 p.m., Saturday – Sunday, Holidays; and

5. Service is limited to a maximum of 1,000 customers until the new Customer Service Information System ("CIS") is implemented.

Q. How did you determine proposed customer charge and minimum charge for the single-phase service and three-phase service?

A. The proposed customer charge and minimum charge for Single-Phase Service and for Three-Phase Service are based on the levels filed in support of the Settlement Agreement of September 2005 in Docket No. 04-0113, HECO's 2005 test year rate case.

Q. How were the proposed time-of-use energy rates determined?

A. The proposed time-of-use energy rates are based on the same differences from regular Schedule R rates that were proposed for Schedule TOU-R in Docket No. 04-0113, HECO's 2005 test year rate case.

Q. Were the proposed time-of-use rating periods for Schedule TOU-R also previously proposed in Docket 04-0113?

A. Yes. The proposed time-of-use rate periods were outlined and proposed for Schedule TOU-R only in Docket 04-0113, HECO's 2005 test year rate case.

<u>Schedule TOU-C – Commercial Time-of-Use Service</u>

Q. Please describe HECO's proposed new Schedule TOU-C?

A. HECO's proposed new Schedule TOU-C is a Time-of-Use Service applicable to commercial customers served under Schedule G or Schedule J. This new time-of-use service provides two options: (1) Non-Demand Service for commercial customers with consumption not exceeding 5000 kWh per month or 25 kW, and (2) Demand Service for customers with consumption greater than 5000 kWh per month or at least 25 kW but less than 300 kW. The Non-Demand Service provides the same customer and minimum charges as proposed for Schedule G and time-differentiated energy rates. Demand Service provides the same customer charge by service phase as proposed for Schedule J, on-peak demand charge, and time-differentiated energy rates.

Q. What are the proposed rates for Schedule TOU-C?

A. The proposed rates for Schedule TOU-C are the following:

Non-Demand Service:

1. Customer Charge of \$30.00 per month for Single-Phase Service and \$55.00 per month for Three-Phase Service – the same as proposed for Schedule G and discussed above.
2. The proposed TOU Energy Rates are:

   Priority Peak Period = 24.9393 ¢/kWh
   Mid-Peak Period = 21.9393 ¢/kWh
   Off-Peak Period = 14.9393 ¢/kWh
3. Minimum Charge of \$30.00 per month for Single-Phase Service and \$55.00 per month for Three-Phase Service – the same as proposed for Schedule G and discussed above.

Demand Service:

1. Customer Charge of \$50.00 for Single-Phase Service and \$70.00 for Three-Phase Service – the same as proposed for Schedule J and discussed above.
2. Demand Charge of \$19.50 per kW if customer's maximum demand occurs during the priority peak period and \$12.00 per kW if it occurs during the mid-peak period.
3. The proposed TOU Energy Rates are:

   Priority Peak Period = 20.1766 ¢/kWh
   Mid-Peak Period = 17.1766 ¢/kWh
   Off-Peak Period = 12.0000 ¢/kWh
4. The minimum charge is the sum of the customer charge and demand charge.

Q. Please explain how the proposed TOU Energy Rates for Schedule TOU-C are derived.

A. The determination of the proposed TOU Energy Rates for Schedule TOU-C is the same as proposed in HECO's Docket No. 04-0113: under the Non-Demand Service, the proposed energy rate for the priority peak period is based on the proposed energy charge for Schedule G adjusted by 5.0 ¢/kWh; the proposed energy rate for mid-peak period is based on the proposed energy rate for Schedule G plus 2.0 ¢/kWh; and the proposed off-peak energy rate is based on the proposed energy charge for Schedule G adjusted by - 5.0 ¢/kWh.

Q. Are the proposed TOU Energy Rates for the Demand Service derived the same way?

A. Yes. The proposed TOU Energy Rates for the Demand Service were derived the same way as the proposed TOU Energy Rates for the Non-Demand Service except for the proposed off-peak energy rate of 12.0000 ¢/kWh, which was set to recover the allocated energy cost for Schedule J.

Q. Please explain the proposed demand charge under the Demand Service.

A. Like the demand charge under existing Schedule U, the proposed demand charge under the Demand Service is applied to the customer's maximum measured kW demand for the billing period. The Company is not proposing a demand ratchet in the determination of the billing demand – the same as in the current effective Schedule U. However, the minimum billing demand of 25 kW still applies. If the customer's maximum measured kW demand for the billing period occurs during the priority peak hours, the priority peak demand charge of $19.50 per kW is applied. If the customer's maximum measured kW demand for the billing period occurs during the mid-peak hours, the mid-peak demand charge of $12.00 per kW is applied. In other words, a customer is charged either the $19.50 per kW Priority Peak demand charge or the $12.00 per kW Mid-Peak demand charge based on when the customer's maximum kW demand occurs. There is no demand charge for kW load during the off-peak hours. The Determination of Demand provision in the proposed new Schedule TOU-C specifies the application of the proposed demand charge for Demand Service.

Q. How did you determine the priority peak demand charge and the mid-peak demand charge?

A. The proposed demand charge of $19.50 per kW for the priority peak period is based on recovering approximately 80% of full unit demand cost for Schedule J, which is the same basis proposed in Docket No. 04-0113. The proposed demand charge of $12.00 per kW for mid-peak period is the same as the proposed demand charge for Schedule J, which again is the same basis proposed in Docket No. 04-0113.

Q. What time-of-use rating periods are proposed for the new Schedule TOU-C?

A. The time-of-use rating periods for the new Schedule TOU-C are the same as those used in the current effective load management riders. These time-of-use rating periods are:

Mid-Peak Period:	7:00 A.M. – 5:00 P.M., Monday – Friday
	7:00 A.M. – 9:00 P.M., Saturday–Sunday
Off-Peak Period:	9:00 P.M. – 7:00 A.M., Daily

Schedule SS – Standby Service

Q. What are the proposed Schedule SS rates?

A. The proposed Schedule SS Standby Service rates are as described in the August

28, 2006 filing in Docket No. 03-0371 in response to Decision and Order No. 22248. The proposed rate structure and terms and conditions are identical to what was filed. The only difference is in the proposed rate levels. The standby service rates filed in Docket No. 03-0371 were based on the cost of service filed in rebuttal in Docket No. 04-0113. The proposed standby service rates are based on the cost of service filed in this docket and are as follows:

Proposed Reservation Demand Charge per kW: Schedule J, $10.08 per kW; Schedule PT, $8.55 per kW; Schedule PP $10.89 per kW; and Schedule PS, $12.48 per kW.

Proposed Daily Demand Charge per kW: Schedule J, $0.38 per kW; Schedule PT, $0.46 per kW; Schedule PP $0.45 per kW; and Schedule PS, $0.47 per kW.

Proposed Backup Energy Charge per kWh: Schedule J, $0.098 per kWh; Schedule PT, $0.096 per kWh; Schedule PP $0.102 per kWh; and Schedule PS, $0.104 per kWh.

Q. Can the standby services rates filed in Docket No. 03-0371 go into effect prior to approval of new standby service rates in this rate case?

A. Yes, the Schedule SS, Standby Service can go into effect if approved by the Commission in Docket No. 03-0371; however, the rate levels would be as proposed in the August 28, 2006 filing.

ENERGY POLICY ACT OF 2005

Q. Why is HECO addressing time-based rates in this proceeding?

A. HECO maintains that a general rate case is the proper forum to explore the time-based rates covered by Section 1252 of the Energy Policy Act of 2005 ("EPACT

2005").

Q. What are time-based rates?

A. As defined by EPACT 2005, a time-based rate schedule is a "schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's cost of generating and purchasing electricity at the wholesale level." The types of time-based rate schedules that may be offered include, among others:

1) Time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall.

2) Critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption.

3) Real-time pricing whereby electricity prices are set for a specific time period on an advance or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly.

4) Credits for consumers with large loads who enter into pre-established peak

load reduction agreements that reduce a utility's planned capacity obligations.

Q. What does EPACT 2005 require with respect to time-based rates?

A. EPACT 2005 requires that each State regulatory authority conduct an investigation and issue a decision as to whether it is appropriate to implement the following standards:

1) Each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

2) Each electric utility shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate.

Q. What are the benefits of time-based rates?

A. To the extent that an electric utility's generation and purchased energy costs reflect the need for capacity such that costs are higher when the need for capacity is greater, time-based rates can send appropriate price signals to the consumer. With this pricing information, the consumer can then choose between consuming electricity now or deferring consumption to another, less costly, time period. Deferring consumption improves reliability by reducing the load on existing generators and purchased power providers.

Q. If the rate design proposals in this proceeding are approved by the Commission would HECO comply with the first standard?

A. Yes, HECO's rate proposals in this proceeding (and its similar rate proposals in

HECO's 2005 test year rate case) will provide a time-of-use rate schedule for each of its customer classes (except for Schedule F, Street and Playground Lighting, customers, which do not have significant flexibility to shift load). Should all of the proposed voluntary time-based rates be approved, the portfolio of time-of-use rates will include:

	Time-Based Rate	Applicable Customer Class
1)	TOU-R, Residential Time-of-Use Service	Sch. R & E
2)	TOU-C, Commercial Time-of-Use Service	Sch. G, J, H
3)	Rider T, Time-of-Day Rider	Sch. J, PS, PP, PT
4)	Rider M, Off-Peak and Curtailable Service	Sch. J, PS, PP, PT
5)	Schedule U, Time-of-Use Service	Sch. PS, PP, PT

In addition, in order to enable the customer to manage his energy use, each customer will be provided with a time-of-use meter so that the appropriate period pricing can be accurately billed on a monthly basis.

Q. Is HECO investigating new metering technology?

A. Yes. Even though HECO proposes to implement proposed time-of-use rate options with existing metering technology, HECO continues to proactively investigate Advanced Metering Infrastructure ("AMI") solutions. For example, in October 2006, HECO agreed to partner with Sensus Metering Systems to field test the FlexNet system, which is a full two-way fixed network AMI system that delivers interval meter data. The FlexNet system can facilitate time-of-use pricing options, as well as transmit meter status information. This pilot program will include approximately 500 Sensus "smart" meters in the Honolulu area.

Q. Does HECO currently comply with the second standard?

A. Yes. For each participant in its existing or proposed time-of-use rate options, HECO provides or will provide a time-of-use meter to record and properly reflect period pricing.

Q. Does HECO currently offer any of the other types of time-based pricing?

A. Yes. HECO also provides credits for consumers with large loads who enter into pre-established peak load reduction agreements through its DSM load management program, the CIDLC Program.

Under the CIDLC Program, HECO pays a monthly incentive to customers (which can be a credit to the customers' bills) who install a load control receiver on selected customer loads. The load control receiver interrupts the selected loads under two conditions: 1) when, due to an unanticipated generation unit outage or some other problem on the system, system frequency falls to a pre-determined setpoint, the load control receiver opens the circuit and drops the load, and 2) when a reserve capacity shortfall is anticipated, HECO may manually send a signal to the load control receiver to open the circuit after providing the customer with at least one hour of advanced notice. Under either condition, the activation of the load control receiver results in a reduction in the amount of capacity needed from supply-side resources to avoid a system outage. As indicated earlier in this testimony, HECO plans to expand the options available under this program, and make certain other modifications to the program.

Q. What is the status of critical peak pricing and real-time pricing, the other two examples of time-based rates included in EPACT 2005?

A. Because HECO lacks access to a wholesale market (i.e., operates a stand alone system on the island of Oahu) a pricing signal to drive critical peak pricing and real-time pricing is not available to the Company. Therefore, the Company is not proposing critical peak and real-time pricing at this time.

Q. What is HECO's recommendation regarding the time-based metering and communications standards included in the Energy Policy Act of 2005?

A. HECO recommends that the Commission's adoption of the standards articulated the Energy Policy Act of 2005 is not necessary because:

1) the Company will be in compliance with the first standard once the proposed rate design is approved, and
2) HECO is already proactively investigating advanced metering and telecommunications infrastructure (AMI) solutions that will enhance the ability of the consumer to manage his energy use and cost.

Q. Please summarize HECO's position.

A. HECO has independently and proactively proposed to offer time-of-use rate options to all customer rate classes that give customers the ability to manage their electric bills by modifying their energy consumption. HECO is also investigating AMI solutions that may enable future and/or modified time-of-use rate options. HECO's AMI research and its proposed time-of-use tariffs are consistent with the standards put forth by the Energy Policy Act of 2005. Thus, it is not necessary for the Commission to adopt the EPACT 2005 time-based rates standards.

SUMMARY

Q. Please summarize your testimony.

A. My testimony presented the Company's embedded and marginal cost-of-service studies, the basis and determination of the proposed rates, and the proposed changes to the Company's tariffs. In addition to the proposed changes to the current rate schedules, the Company is also proposing three new rate schedules – Schedule TOU-R, Schedule TOU-C, and cost-based changes to its new schedule filed in Docket No. 03-0371, Schedule SS – for Commission approval, as well as changes to the service-related charges including the Returned Checks Charge, Field Collection Charge, and Service Establishment Charge.

Q. Does this complete your testimony?

A. Yes.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

SUMMARY OF CLASS REVENUE REQUIREMENTS AND CLASS RATES OF RETURN
AT PRESENT RATES AND AT PROPOSED RATES

	Present Rates			Proposed Rates			Proposed Increase	
Rate Class	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Amount ($000s)	Percent (%)
Schedule R	$415,723.4	0.51%	25.68%	$463,564.9	5.70%	63.90%	$47,841.5	11.51%
Schedule G	$77,691.4	4.29%	216.79%	$86,424.7	9.33%	104.60%	$8,733.3	11.24%
Schedule J	$358,924.9	4.13%	209.00%	$398,587.8	12.11%	135.76%	$39,662.9	11.05%
Schedule H	$7,077.7	1.17%	59.15%	$7,873.7	7.48%	83.86%	$796.0	11.25%
Schedule PS	$135,059.5	2.29%	115.82%	$150,691.1	11.67%	130.83%	$15,631.6	11.57%
Schedule PP	$319,103.4	1.72%	86.75%	$354,407.5	11.49%	128.81%	$35,304.1	11.06%
Schedule PT	$26,047.3	2.49%	125.63%	$27,887.5	10.57%	118.50%	$1,840.2	7.06%
Schedule F	$6,751.4	-2.95%	-149.04%	$7,628.8	3.67%	41.14%	$877.4	13.00%
Total Sales Revenues	$1,346,379.0			$1,497,066.0			$150,687.0	11.19%
Other Operating Revenues	$3,898.0			$4,716.8			$818.8	21.01%
Total Revenues	$1,350,277.0	1.98%	100.00%	$1,501,782.8	8.92%	100.00%	$151,505.8	11.22%

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

SUMMARY OF CLASS REVENUE REQUIREMENTS AND CLASS RATES OF RETURN
AT CURRENT EFFECTIVE RATES AND AT PROPOSED RATES

	Current Effective Rates			Proposed Rates			Proposed Increase	
Rate Class	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Amount ($000s)	Percent (%)
Schedule R	$432,975.6	2.36%	54.11%	$463,564.9	5.70%	63.90%	$30,589.3	7.06%
Schedule G	$80,721.8	6.02%	138.27%	$86,424.7	9.33%	104.60%	$5,702.9	7.06%
Schedule J	$372,286.2	6.82%	156.52%	$398,587.8	12.12%	135.87%	$26,301.6	7.06%
Schedule H	$7,354.1	3.35%	76.97%	$7,873.7	7.49%	83.97%	$519.6	7.07%
Schedule PS	$140,747.4	5.70%	130.83%	$150,691.1	11.67%	130.83%	$9,943.7	7.06%
Schedule PP	$331,021.2	5.01%	115.08%	$354,407.5	11.50%	128.92%	$23,386.3	7.06%
Schedule PT	$26,047.3	2.49%	57.09%	$27,887.5	10.59%	118.72%	$1,840.2	7.06%
Schedule F	$7,125.4	-0.13%	-3.01%	$7,628.8	3.67%	41.14%	$503.4	7.06%
Total Sales Revenues	$1,398,279.0			$1,497,066.0			$98,787.0	7.06%
Other Operating Revenues	$3,947.1			$4,716.8			$769.7	19.50%
Total Revenues	$1,402,226.1	4.36%	100.00%	$1,501,782.8	8.92%	100.00%	$99,556.7	7.10%

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HAWAIIAN ELECTRIC COMPANY, INC.
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SUMMARY OF CLASS RATES OF RETURN ON RATE BASE AT PRESENT RATES

Rate Class	Total Operating Revenues ($000s)	Total Operating Expenses ($000s)	Total Operating Income ($000s)	Rate base ($000s)	Return on Rate Base (%)
Schedule R	$418,192.3	$415,550.6	$2,641.7	$519,691.3	0.51%
Schedule G	$78,002.4	$73,827.0	$4,175.4	$97,369.8	4.29%
Schedule J	$359,532.4	$348,058.6	$11,473.8	$277,547.3	4.13%
Schedule H	$7,103.8	$7,021.2	$82.6	$7,059.7	1.17%
Schedule PS	$135,207.0	$133,077.0	$2,130.0	$92,978.2	2.29%
Schedule PP	$319,402.0	$315,944.6	$3,457.4	$201,457.1	1.72%
Schedule PT	$26,062.2	$25,747.0	$315.2	$12,686.3	2.49%
Schedule F	$6,774.9	$6,993.0	($218.1)	$7,398.8	-2.95%
TOTAL	$1,350,277.0	$1,326,219.0	$24,058.0	$1,216,188.5	1.98%

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

SUMMARY OF CLASS RATES OF RETURN ON RATE BASE AT CURRENT EFFECTIVE RATES

Rate Class	Total Operating Revenues ($000s)	Total Operating Expenses ($000s)	Total Operating Income ($000s)	Rate base ($000s)	Return on Rate Base (%)
Schedule R	$435,474.8	$423,232.8	$12,242.0	$519,497.0	2.36%
Schedule G	$81,037.9	$75,175.3	$5,862.6	$97,336.9	6.02%
Schedule J	$372,903.2	$353,990.7	$18,912.5	$277,377.6	6.82%
Schedule H	$7,380.7	$7,144.1	$236.6	$7,056.3	3.35%
Schedule PS	$140,896.1	$135,601.3	$5,294.8	$92,911.6	5.70%
Schedule PP	$331,321.7	$321,230.4	$10,091.3	$201,296.7	5.01%
Schedule PT	$26,062.2	$25,747.0	$315.2	$12,673.1	2.49%
Schedule F	$7,149.5	$7,159.2	($9.7)	$7,395.3	-0.13%
TOTAL	$1,402,226.1	$1,349,280.8	$52,945.3	$1,215,544.5	4.36%

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

SUMMARY OF CLASS RATES OF RETURN ON RATE BASE AT PROPOSED RATES

Rate Class	Total Operating Revenues ($000s)	Total Operating Expenses ($000s)	Total Operating Income ($000s)	Rate base ($000s)	Return on Rate Base (%)
Schedule R	$466,717.1	$437,109.0	$29,608.1	$519,107.0	5.70%
Schedule G	$86,815.5	$77,740.2	$9,075.3	$97,265.3	9.33%
Schedule J	$399,235.4	$365,669.2	$33,566.2	$277,053.1	12.12%
Schedule H	$7,904.7	$7,376.8	$527.9	$7,050.0	7.49%
Schedule PS	$150,842.2	$140,013.1	$10,829.1	$92,788.5	11.67%
Schedule PP	$354,711.6	$331,598.7	$23,112.9	$201,009.5	11.50%
Schedule PT	$27,902.4	$26,562.6	$1,339.8	$12,650.5	10.59%
Schedule F	$7,653.9	$7,382.8	$271.1	$7,388.7	3.67%
TOTAL	$1,501,782.8	$1,393,452.4	$108,330.4	$1,214,312.6	8.92%

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

PROPOSED ALLOCATION OF RATE INCREASE BY RATE CLASS FROM PRESENT RATES

Rate Class	Sales Revenues at Present Rates ($000s)	Sales Revenues at Proposed Rates ($000s)	PROPOSED INCREASE ($000s)	% Increase	% of Total
Schedule R	$415,723.4	$463,564.9	$47,841.5	11.51%	31.75%
Schedule G	$77,691.4	$86,424.7	$8,733.3	11.24%	5.80%
Schedule J	$358,924.9	$398,587.8	$39,662.9	11.05%	26.32%
Schedule H	$7,077.7	$7,873.7	$796.0	11.25%	0.53%
Schedule PS	$135,059.5	$150,691.1	$15,631.6	11.57%	10.37%
Schedule PP	$319,103.4	$354,407.5	$35,304.1	11.06%	23.43%
Schedule PT	$26,047.3	$27,887.5	$1,840.2	7.06%	1.22%
Schedule F	$6,751.4	$7,628.8	$877.4	13.00%	0.58%
Total Sales Revenues	$1,346,379.0	$1,497,066.0	$150,687.0	11.19%	100.00%
Other Operating Revenues	$3,898.0	$4,716.8	$818.8	21.01%	
Total Revenues	$1,350,277.0	$1,501,782.8	$151,505.8	11.22%	

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

PROPOSED ALLOCATION OF RATE INCREASE BY RATE CLASS FROM CURRENT EFFECTIVE RATES

Rate Class	Sales Revenues at Cur. Eff. Rates ($000s)	Sales Revenues at Proposed Rates ($000s)	PROPOSED INCREASE ($000s)	% Increase	% of Total
Schedule R	$432,975.6	$463,564.9	$30,589.3	7.06%	30.96%
Schedule G	$80,721.8	$86,424.7	$5,702.9	7.06%	5.77%
Schedule J	$372,286.2	$398,587.8	$26,301.6	7.06%	26.62%
Schedule H	$7,354.1	$7,873.7	$519.6	7.07%	0.53%
Schedule PS	$140,747.4	$150,691.1	$9,943.7	7.06%	10.07%
Schedule PP	$331,021.2	$354,407.5	$23,386.3	7.06%	23.67%
Schedule PT	$26,047.3	$27,887.5	$1,840.2	7.06%	1.86%
Schedule F	$7,125.4	$7,628.8	$503.4	7.06%	0.51%
Total Sales Revenues	$1,398,279.0	$1,497,066.0	$98,787.0	7.06%	100.00%
Other Operating Revenues	$3,947.1	$4,716.8	$769.7	19.50%	
Total Revenues	$1,402,226.1	$1,501,782.8	$99,556.7	7.10%	

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

ALLOCATION OF RATE INCREASE BASED ON EQUAL CLASS ROR FROM PRESENT RATES

Rate Class	Sales Revenues at Present Rates ($000s)	Rev Requirements at Equal ROR ($000s)	REVENUE INCREASE ($000s)	% Increase	% of Total	CLASS RATES OF RETURN At Present Rates (%)	At Equal ROR (%)
Schedule R	$415,723.4	$493,506.0	$77,782.6	18.71%	51.6%	0.51%	8.92%
Schedule G	$77,691.4	$85,707.1	$8,015.7	10.32%	5.3%	4.29%	8.92%
Schedule J	$358,924.9	$382,716.2	$23,791.3	6.63%	15.8%	4.13%	8.92%
Schedule H	$7,077.7	$8,054.7	$977.0	13.80%	0.6%	1.17%	8.92%
Schedule PS	$135,059.5	$146,115.4	$11,055.9	8.19%	7.3%	2.29%	8.92%
Schedule PP	$319,103.4	$345,129.3	$26,025.9	8.16%	17.3%	1.72%	8.92%
Schedule PT	$26,047.3	$27,510.1	$1,462.8	5.62%	1.0%	2.49%	8.92%
Schedule F	$6,751.4	$8,325.4	$1,574.0	23.31%	1.0%	-2.95%	8.91%
Total Sales Revenues	$1,346,379.0	$1,497,064.2	$150,685.2	11.19%	100.0%		
Other Operating Revenues	$3,898.0	$4,716.8	$818.8	21.01%			
TOTAL SYSTEM	$1,350,277.0	$1,501,781.0	$151,504.0	11.22%		1.98%	8.92%

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

ALLOCATION OF RATE INCREASE BASED ON EQUAL CLASS ROR FROM CURRENT EFFECTIVE RATES

Rate Class	Sales Revenues at Cur. Eff. Rates	Rev Requirements at Equal ROR	REVENUE INCREASE			CLASS RATES OF RETURN	
	($000s)	($000s)	($000s)	% Increase	% of Total	At Cur. Eff. Rates (%)	At Equal ROR (%)
Schedule R	$432,975.6	$493,506.0	$60,530.4	13.98%	61.3%	2.36%	8.92%
Schedule G	$80,721.8	$85,707.1	$4,985.3	6.18%	5.0%	6.02%	8.92%
Schedule J	$372,286.2	$382,716.2	$10,430.0	2.80%	10.6%	6.82%	8.92%
Schedule H	$7,354.1	$8,054.7	$700.6	9.53%	0.7%	3.35%	8.92%
Schedule PS	$140,747.4	$146,115.4	$5,368.0	3.81%	5.4%	5.70%	8.92%
Schedule PP	$331,021.2	$345,129.3	$14,108.1	4.26%	14.3%	5.01%	8.92%
Schedule PT	$26,047.3	$27,510.1	$1,462.8	5.62%	1.5%	2.49%	8.92%
Schedule F	$7,125.4	$8,325.4	$1,200.0	16.84%	1.2%	-0.13%	8.92%
Total Sales Revenues	$1,398,279.0	$1,497,064.2	$98,785.2	7.06%	100.0%		
Other Operating Revenues	$3,947.1	$4,716.8	$769.7	19.50%			
TOTAL SYSTEM	$1,402,226.1	$1,501,781.0	$99,554.9	7.10%		4.36%	8.92%

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

COMPARISON OF CLASS REVENUE REQUIREMENTS AT PRESENT RATES, AT PROPOSED RATES AND AT EQUAL RATES OF RETURN

				CLASS RATES OF RETURN		
Rate Class	Sales Revenues at Present Rates ($000s)	Sales Revenues at Proposed Rates ($000s)	Sales Revenues at Equal ROR ($000s)	At Present Rates (%)	At Proposed Rates (%)	At Equal ROR (%)
Schedule R	$415,723.4	$463,564.9	$493,506.0	0.51%	5.70%	8.92%
Schedule G	$77,691.4	$86,424.7	$85,707.1	4.29%	9.33%	8.92%
Schedule J	$358,924.9	$398,587.8	$382,716.2	4.13%	12.11%	8.92%
Schedule H	$7,077.7	$7,873.7	$8,054.7	1.17%	7.48%	8.92%
Schedule PS	$135,059.5	$150,691.1	$146,115.4	2.29%	11.67%	8.92%
Schedule PP	$319,103.4	$354,407.5	$345,129.3	1.72%	11.49%	8.92%
Schedule PT	$26,047.3	$27,887.5	$27,510.1	2.49%	10.57%	8.92%
Schedule F	$6,751.4	$7,628.8	$8,325.4	-2.95%	3.67%	8.91%
Total Sales Revenues	$1,346,379.0	$1,497,066.0 [1]	$1,497,064.2 [1]			
Other Operating Revenues	$3,898.0	$4,716.8	$4,716.8			
TOTAL SYSTEM	$1,350,277.0	$1,501,782.8 [1]	$1,501,781.0 [1]	1.98%	8.92%	8.92%

[1] The totals may not exactly equal due to rounding.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

COMPARISON OF CLASS REVENUE REQUIREMENTS AT PRESENT RATES, AT CURRENT EFFECTIVE RATES AND AT EQUAL RATES OF RETURN

Rate Class	Sales Revenues at Cur. Eff. Rates ($000s)	Sales Revenues at Proposed Rates ($000s)	Sales Revenues at Equal ROR ($000s)	CLASS RATES OF RETURN At Cur. Eff. Rates (%)	At Proposed Rates (%)	At Equal ROR (%)
Schedule R	$432,975.6	$463,564.9	$493,506.0	2.36%	5.70%	8.92%
Schedule G	$80,721.8	$86,424.7	$85,707.1	6.02%	9.33%	8.92%
Schedule J	$372,286.2	$398,587.8	$382,716.2	6.82%	12.12%	8.92%
Schedule H	$7,354.1	$7,873.7	$8,054.7	3.35%	7.49%	8.92%
Schedule PS	$140,747.4	$150,691.1	$146,115.4	5.70%	11.67%	8.92%
Schedule PP	$331,021.2	$354,407.5	$345,129.3	5.01%	11.50%	8.92%
Schedule PT	$26,047.3	$27,887.5	$27,510.1	2.49%	10.59%	8.92%
Schedule F	$7,125.4	$7,628.8	$8,325.4	-0.13%	3.67%	8.92%
Total Sales Revenues	$1,398,279.0	$1,497,066.0 [1]	$1,497,064.2 [1]			
Other Operating Revenues	$3,947.1	$4,716.8	$4,716.8			
TOTAL SYSTEM	$1,402,226.1	$1,501,782.8 [1]	$1,501,781.0 [1]	4.36%	8.92%	8.92%

[1] The totals may not exactly equal due to rounding.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

SUMMARY OF COST COMPONENTS BY RATE CLASS AT PROPOSED RATES

Rate Class	COST COMPONENTS AT PROPOSED RATES							
	DEMAND COSTS		ENERGY COSTS		CUSTOMER COSTS		TOTAL COSTS	
	($000s)	(%)	($000s)	(%)	($000s)	(%)	($000s)	(%)
Schedule R	$146,033.8	29.76%	$251,594.8	27.58%	$65,936.4	70.11%	$463,565.0	30.96%
Schedule G	$27,707.4	5.65%	$44,163.5	4.84%	$14,553.6	15.47%	$86,424.5	5.77%
Schedule J	$142,042.5	28.94%	$246,270.7	27.00%	$10,274.4	10.92%	$398,587.6	26.62%
Schedule H	$2,569.1	0.52%	$4,800.1	0.53%	$504.5	0.54%	$7,873.7	0.53%
Schedule PS	$50,361.3	10.26%	$99,207.0	10.87%	$1,122.9	1.19%	$150,691.2	10.07%
Schedule PP	$111,497.9	22.72%	$241,457.9	26.47%	$1,452.1	1.54%	$354,407.9	23.67%
Schedule PT	$7,473.7	1.52%	$20,383.3	2.23%	$30.6	0.03%	$27,887.6	1.86%
Schedule F	$3,073.6	0.63%	$4,395.6	0.48%	$175.0	0.19%	$7,644.2	0.51%
TOTAL	$490,759.3	100.00%	$912,272.9	100.00%	$94,049.5	99.99%	$1,497,081.7	100.00%
PERCENT OF TOTAL	32.78%		60.94%		6.28%		100.00%	

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

SUMMARY OF UNIT COST COMPONENTS BY RATE CLASS AT PROPOSED RATES

	Unit Cost Components At Proposed Rates			
Rate Class	Unit Demand Cost ($/kW/mo.)	Unit Energy Cost (¢/kWh)	Unit Customer Cost ($/Customer/mo.)	Total Unit Cost (¢/kWh)
Schedule R	$9.59	11.818	$21.03	21.775
Schedule G	$16.06	11.878	$46.59	23.245
Schedule J	$24.30	11.904	$129.96	19.267
Schedule H	$20.21	11.852	$56.34	19.441
Schedule PS	$30.12	11.869	$487.36	18.028
Schedule PP	$27.68	11.710	$742.39	17.188
Schedule PT	$24.28	11.637	$637.50	15.921
Schedule F	$27.08	11.629	$33.38	20.223
TOTAL	$16.88	11.816	$26.53	19.390

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

SUMMARY OF COST COMPONENTS BY RATE CLASS AT EQUAL RATES OF RETURN

	COST COMPONENTS AT EQUAL RATES OF RETURN							
Rate Class	DEMAND COSTS		ENERGY COSTS		CUSTOMER COSTS		TOTAL COSTS	
	($000s)	(%)	($000s)	(%)	($000s)	(%)	($000s)	(%)
Schedule R	$163,636.6	33.92%	$252,716.8	27.74%	$77,153.7	74.39%	$493,507.1	32.96%
Schedule G	$27,335.1	5.67%	$44,138.4	4.84%	$14,233.2	13.72%	$85,706.7	5.72%
Schedule J	$128,610.9	26.66%	$245,179.3	26.91%	$8,925.6	8.61%	$382,715.8	25.56%
Schedule H	$2,696.1	0.56%	$4,809.7	0.53%	$549.1	0.53%	$8,054.9	0.54%
Schedule PS	$46,197.6	9.58%	$98,826.2	10.85%	$1,091.7	1.05%	$146,115.5	9.76%
Schedule PP	$103,037.6	21.36%	$240,589.3	26.41%	$1,503.0	1.45%	$345,129.9	23.05%
Schedule PT	$7,144.0	1.48%	$20,336.2	2.23%	$29.9	0.03%	$27,510.1	1.84%
Schedule F	$3,690.4	0.77%	$4,427.7	0.49%	$222.5	0.21%	$8,340.6	0.56%
TOTAL	$482,348.3	100.00%	$911,023.6	100.00%	$103,708.7	99.99%	$1,497,080.6	100.00%
PERCENT OF TOTAL	32.22%		60.85%		6.93%		100.00%	

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

SUMMARY OF UNIT COST COMPONENTS BY RATE CLASS AT EQUAL RATES OF RETURN

	Unit Cost Components At Equal Rates of Return			
Rate Class	Unit Demand Cost	Unit Energy Cost	Unit Customer Cost	Total Unit Cost
	($/kW/mo.)	(¢/kWh)	($/Customer/mo.)	(¢/kWh)
Schedule R	$10.75	11.871	$24.61	23.181
Schedule G	$15.84	11.872	$45.57	23.052
Schedule J	$22.00	11.851	$112.91	18.499
Schedule H	$21.19	11.876	$61.35	19.889
Schedule PS	$27.63	11.823	$473.82	17.481
Schedule PP	$25.57	11.668	$768.41	16.738
Schedule PT	$23.21	11.610	$622.91	15.706
Schedule F	$32.51	11.713	$42.43	22.065
TOTAL	$16.79	11.800	$29.25	19.390

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007
SUMMARY OF ALLOCATION FACTORS

ALLOCATION BASIS		Schedule R	Schedule G	Schedule J	Schedule H	Schedule PS	Schedule PP	Schedule PT	Schedule F	Total
Demand Allocation Factors:										
Average-Excess Demand	D1	33.07%	5.58%	26.61%	0.56%	9.57%	22.06%	1.77%	0.79%	100.00%
Class Peak Demand	D2	34.79%	5.83%	27.00%	0.57%	9.45%	21.49%		0.87%	100.00%
Composite NCD	D3	50.51%	6.98%	25.38%	0.61%	9.30%	7.09%		0.14%	100.00%
Energy Allocation Factors:										
Gross Input	E1	27.75%	4.85%	26.91%	0.53%	10.85%	26.41%	2.23%	0.49%	100.00%
Customer Allocation Factors:										
Primary Lines	C1	83.87%	11.53%	3.95%	0.41%	0.07%	0.03%		0.14%	100.00%
Secondary Lines	C2	87.09%	9.80%	2.72%	0.31%	0.05%			0.03%	100.00%
Transformers	C3	33.02%	40.96%	22.31%	1.91%	1.63%			0.17%	100.00%
Services	C4	84.18%	8.97%	5.99%	0.27%	0.13%	0.18%	0.04%	0.24%	100.00%
Meter	C5	62.95%	9.59%	23.90%	0.36%	0.55%	1.94%	0.32%	0.39%	100.00%
Cust Acct Fct	C6	85.12%	10.77%	3.46%	0.31%	0.10%	0.08%	0.00%	0.17%	100.00%
Bad Debt	C7	66.31%	9.08%	14.18%	0.92%	6.11%	3.27%	0.00%	0.13%	100.00%
Cust Serv Fct	C8	55.91%	1.06%	16.64%	0.05%	9.06%	17.23%	0.04%	0.01%	100.00%
Avg Cust	C10	88.44%	8.81%	2.23%	0.25%	0.07%	0.06%	0.00%	0.15%	100.00%

Hawaiian Electric Company, Inc.
Docket No. 2006-0386, Test-Year 2007
Energy Loss Analysis By Rate Class

		Total System	Total R/E	G	J-DP	J-DS	J-Sec	J-Nwk	Total J	H	P-TP	P-DP	P-DS	P-SEC	P-Nwk	F-DP	F-Sec	Total F
1	Energy Sales, Mwh	7,720,800	2,128,900	371,800	206,673	21,102	1,782,545	56,064	2,068,800	40,500	175,161	2,040,472	21,511	682,206	153,650	31,261	6,539	37,800
	Line, Transformer Losses:																	
2	Generation Step Up	8,308	2,291	400	222	23	1,918	60	2,226	44	189	2,196	23	734	165	34	7	41
3	Transm Line Loss 138 kv	42,595	11,745	2,051	1,140	116	9,834	309	11,413	221	966	11,257	119	3,764	848	173	36	209
4	T 138 to T 46 Transf	18,198	5,018	876	487	50	4,202	132	4,876	96	413	4,809	51	1,608	362	74	15	89
5	Transm Line Loss 46 Kv	16,852	4,647	812	451	46	3,891	122	4,516	88	382	4,454	47	1,489	335	68	14	83
6	Transm To Pri Transf	25,923	7,314	1,277	710	73	6,124	193	7,108	139	-	7,010	74	2,344	528	107	23	130
7	Pri Line Loss	13,106	3,698	646	359	37	3,096	97	3,593	70	-	3,544	37	1,185	267	54	11	66
8	Pri to Sec Transf	68,926	27,846	4,865	-	276	23,326	733	24,335	530	-	-	281	8,927	2,013	-	85	129
9	Sec Line Loss	24,341	11,416	1,992	-	-	9,551	300	9,851	217	-	-	-	-	828	-	35	37
10	Total Line and Trsf Loss	218,249	73,975	12,919	3,369	621	61,942	1,946	67,918	1,405	1,950	33,270	632	20,051	5,346	510	226	784
11	Company Use	15,400	4,246	742	412	42	3,556	112	4,126	81	349	4,070	43	1,361	306	62	13	76
12	Unaccounted For	154,751	42,671	7,453	4,143	422	35,729	1,123	41,466	812	3,511	40,898	432	13,674	3,080	627	132	758
13	Net Input	8,109,200	2,249,792	392,914	214,597	22,187	1,883,772	59,245	2,182,310	42,798	180,971	2,118,710	22,618	717,292	162,382	32,460	6,910	39,418
14	Purchased Power	3,372,700	935,722	163,407	89,242	9,241	783,478	24,654	907,661	17,808	75,279	881,185	9,410	298,315	67,521	13,491	2,867	16,391
15	Net Generation	4,736,500	1,314,070	229,507	125,355	12,946	1,100,294	34,591	1,274,649	24,990	105,692	1,237,525	13,208	418,977	94,861	18,969	4,043	23,027
16	Station Use	301,952	83,771	14,630	7,993	824	70,143	2,204	81,258	1,594	6,737	78,891	842	26,711	6,048	1,208	257	1,470
17	Gross Generation	5,038,452	1,397,841	244,137	133,348	13,770	1,170,437	36,795	1,355,907	26,584	112,429	1,316,416	14,050	445,688	100,909	20,177	4,300	24,497
	Gross Input By Voltage:																	
18	Gross I	8,411,152	2,333,563	407,544	222,590	23,011	1,953,915	61,449	2,263,568	44,392	187,708	2,197,601	23,460	744,003	168,430	33,668	7,167	40,888
19	Gross II	8,220,841	2,333,563	407,544	222,590	23,011	1,953,915	61,449	2,263,568	44,392	0	2,197,601	23,460	744,003	168,430	33,668	7,167	40,888
20	Gross III	5,720,463	2,333,563	407,544	0	0	1,953,915	61,449	2,015,364	44,392	0	0	0	744,003	168,430	0	7,167	7,167
21	Gross To Sales Ratio	1.0894	1.0961	1.0961	1.077	1.0905	1.0961	1.0961	1.0941	1.0961	1.0716	1.077	1.0906	1.0906	1.0962	1.0770	1.096	1.0817
22	Net To Sales Ratio	1.0503	1.0568	1.0568	1.0383	1.0514	1.0568	1.0567	1.0549	1.0567	1.0332	1.0383	1.0515	1.0514	1.0568	1.0384	1.0567	1.0428

Derivation and Allocation Basis:
L1: Test-Year Sales Forecasts
L2: .001754 x Net Gen x % Sales
L3: .008993 x Net Gen x % Sales
L4: .003842 x Net Gen x % Sales
L5: .003558 x Net Gen x % Sales
L6: .005473 x Net Gen x % Sales Excl TP
L7: .002767 x Net Gen x % Sales Excl TP, TS
L8: .014552 x Net Gen x % Sales Excl TP, TS, DP
L9: .005139 x Net Gen x % Sales Excl TP, TS, DP, DS, PSEC
L10: Sum(L2:L9)
L11: % Sales
L12: % Sales

L13: Sum(L1, L10, L11, L12)
L14: % Net Input
L15: (L13 - L14)
L16: % Net Generation
L17: Sum(L15:L16)
L18: Sum(L14, L17)
L19: L18 Excl Transmission
L20: L18 Excl Transmission, Primary
L21: L18 ÷ L1
L22: L13 ÷ L1

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

COMPARISON BETWEEN UNIT EMBEDDED COSTS [1] AND UNIT MARGINAL COSTS BY FUNCTION

Cost Components	Unit Embedded Costs At Equal ROR	Unit Marginal Cost
Demand Costs:	($/kW/mo.)	($/kW/mo.)
Production	$11.57	$12.67
Transmission	$2.43	$4.29
Distribution	$2.79	$4.23
TOTAL	$16.79	$21.19
Energy Costs:	(¢/kWh)	(¢/kWh)[2]
Priority Peak		12.93
Mid-Peak		12.76
Off-Peak		11.34
TOTAL	11.80	12.01
Customer Costs:	($/Customer/mo.)	($/Customer/mo.)
Schedule R	$24.61	$10.33
Schedule G	$45.57	$12.67
Schedule J	$112.91	$42.50
Schedule H	$61.35	$13.50
Schedule PS	$473.82	$34.42
Schedule PP	$768.61	$99.92
Schedule PT	$622.91	$668.42
Schedule F	$42.43	$18.00
TOTAL SYSTEM	$29.25	

[1] At proposed rates.
[2] Average for 2007-2011.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007
MARGINAL COST STUDY

MARGINAL ENERGY COSTS BY TIME-OF-USE RATING PERIOD

YEAR	Priority Peak	Mid-Peak	Off-Peak	TOTAL
	(A)	(B)	(C)	(D)
	Transmission Voltage Service (¢/kWh)			
2007	13.51	13.36	12.09	12.69
2008	12.87	12.68	11.14	11.87
2009	12.35	12.15	10.73	11.40
2010	11.46	11.33	10.01	10.63
2011	11.43	11.27	10.05	10.63
	Primary Voltage Service (¢/kWh)			
2007	14.01	13.86	12.54	13.16
2008	13.35	13.15	11.56	12.32
2009	12.81	12.61	11.13	11.83
2010	11.89	11.75	10.39	11.03
2011	11.86	11.70	10.42	11.03
	Secondary Voltage Service (¢/kWh)			
2007	14.18	14.02	12.69	13.32
2008	13.51	13.30	11.70	12.46
2009	12.96	12.75	11.26	11.97
2010	12.02	11.89	10.51	11.16
2011	12.00	11.83	10.54	11.15
Average	12.93	12.76	11.34	12.01

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

DETERMINATION OF BASE FUEL ENERGY CHARGE

	In Cents Per kWh		
L1	Weighted Base Central Station + Other Generation Cost	6.91568	HECO-936, line 23
L2	Revenue Tax Requirements Multiplier	1.0975	HECO-936, line 25
L3 = L1 * L2	Base Central Station + Other Generation Cost at Revenue Level	7.58996	
L4	Weighted Base DG (Distributed Generation) Energy Cost	0.05072	HECO-936, line 32
L5	Loss Factor	1.050	HECO-936, line 34
L6	Revenue Tax Requirements Multiplier	1.0975	HECO-936, line 35
L7 = L4*L5*L6	Base DG Energy Cost at Revenue Level	0.05845	
L8	Weighted Base Purchased Energy Cost	2.81647	HECO-936, line 65
L9	Loss Factor	1.050	HECO-936, line 67
L10	Revenue Tax Requirements Multiplier	1.0975	HECO-936, line 68
L11 = L8*L9*L10	Base Purchased Energy Cost at Revenue Level	3.24563	
L12 = L3+L7+L11	Base Fuel Energy Charge	10.8940	

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2006-0386, TEST-YEAR 2007

DISTRIBUTION OF CUSTOMERS AND KWH IN PROPOSED USAGE TIERS

Non-Fuel Energy Charge Tier	% of Customer Bills in Tier	% of Cumulative kWh in Tier
0 to 350 kWh	26.5%	46.0%
350 to 1200 kWh	61.1%	44.6%
Over 1200 kWh	12.4%	9.4%
Total	100.0%	100.0%

Source: HECO Billing Data, January 2005 - December 2005

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 2006-0386, Test-Year 2007 DIRECT TESTIMONY
SCHEDULE R - RESIDENTIAL SERVICE

ESTIMATE OF TEST YEAR REVENUES

	BILLING UNITS	PRESENT RATES UNIT PRICE	PRESENT RATES REVENUES $1000S	PROPOSED RATES UNIT PRICE	PROPOSED RATES REVENUES $1000S
ENERGY CHARGE:	(MWH)	¢/kWh		¢/kWh	
NON-FUEL ENERGY CHARGE	2,128,900	7.7814	$165,658.2		
BASE FUEL ENERGY CHARGE	2,128,900	3.5140	$74,809.5		
SUBTOTAL			$240,467.7		
ENERGY CHARGE:					
BASE FUEL ENERGY CHARGE	2,128,900			10.8940	$231,922.4
NON-FUEL ENERGY CHARGE					
0 - 350 kWh	987,708			8.8981	87,887.2
351 - 1200 kWh	945,734			10.1951	96,418.5
Over 1200 kWh	195,458			11.0878	21,671.9
SUBTOTAL ENERGY					$437,900.0
CUSTOMER CHARGE:	BILLS	$/MONTH		$/MONTH	
1 PHASE CHARGE	3,134,056	7.00	$21,938.4	8.00	$25,072.4
3 PHASE CHARGE	1,568	15.00	$23.5	17.00	$26.7
SUBTOTAL	3,135,624		$21,961.9		$25,099.1
ADJUSTMENTS:					
SCHEDULE E ADJ.			-1081.7		528.4
MINIMUM BILL ADJ. - 1 PHASE			$108.2		$98.2
MINIMUM BILL ADJ. - 3 PHASE			$0.0		$0.1
RESIDENTIAL TOU			$0.0		$0.0
APARTMENT HOUSE:			($59.6)		($60.9)
SUBTOTAL			($1,033.1)		$565.8
TOTAL BASE REVENUE			$261,396.5		$463,564.9
BILL ADJUSTMENTS:					
FUEL OIL ADJUSTMENT:	¢/KWH	7.299	$155,388.4	-	$0.0
RATE ADJUSTMENT (AES REFUND):	(%)	-0.406%	($1,061.5)	-	$0.0
TOTAL REVENUES			$415,723.4		$463,564.9
INTERIM RATE INCREASE REVENUES			$17,252.2		$0.0
TOTAL REVENUE AT CURRENT EFFECTIVE RATES			$432,975.6		$463,564.9

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 2006-0386, Test-Year 2007 DIRECT TESTIMONY
SCHEDULE G - GENERAL SERVICE NON-DEMAND

ESTIMATE OF TEST YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
CUSTOMER CHARGE:	BILLS	$/month		$/month	
1 PHASE - Regular	192,429	20.00	$3,848.6	30.00	$5,772.9
3 PHASE - Regular	119,955	45.00	$5,398.0	55.00	$6,597.5
SUBTOTAL	312,384		$9,246.6		$12,370.4
ENERGY CHARGE:	(MWH)	¢/kWh		¢/kWh	
G: Regular NON-DEMAND	371,800	11.1570	$41,481.7	19.9393	$74,134.3
Total	371,800		$41,481.7		$74,134.3
BASE REVENUE ADJUSTMENTS:					
DP VOLTAGE ADJUSTMENT			($0.2)		($0.3)
DS VOLTAGE ADJUSTMENT			$0.0		$0.0
MINIMUM BILL ADJUSTMENT			$31.7		$0.0
SCHEDULE E ADJUSTMENT			$0.0		($79.9)
TOU-C ADJUSTMENT					$0.0
SUBTOTAL			$31.5		($80.2)
TOTAL BASE REVENUE			$50,759.8		$86,424.5
Other Adjustments:		Rate		Rate	
FUEL OIL ADJUSTMENT:		7.299 ¢/KWH	$27,137.7	- ¢/KWH	$0.0
RATE ADJUSTMENT (AES REFUND):		(0.406) (%)	($206.1)	- (%)	$0.0
TOTAL REVENUES			$77,691.4		$86,424.5
INTERIM RATE INCREASE REVENUES			$3,030.4		$0.0
TOTAL REVENUE AT CURRENT EFFECTIVE RATES			$80,721.8		$86,424.5

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 2006-0386, Test-Year 2007
Schedule J - General Service Demand

Estimate of Test Year Revenues

	PRESENT RATES			PROPOSED RATES		
	BILLING UNITS	UNIT PRICE	REVENUES $000s	BILLING UNITS	UNIT PRICE	REVENUES $000s
ENERGY CHARGE:	(MWH)	¢/kWh		(MWH)	¢/kWh	
0 - 200 KWH/KW	1,198,252	8.6900	$104,128.1	1,217,611	15.7410	$191,664.1
201 - 400 KWH/KW	697,152	7.5419	$52,578.5	666,263	14.5929	$97,227.1
> 400 KWH/KW	173,396	6.5130	$11,293.3	184,926	13.5639	$25,083.2
TOTAL	2,068,800		$167,999.9	2,068,800		$313,974.4
DEMAND CHARGE:	kW	$/kW		kW	$/kW	
ALL BILLING KW	6,609,417	5.75	$38,004.1	6,875,614	12.00	$82,507.4
CUSTOMER CHARGE:	BILLS	$/month		BILLS	$/month	
1 PHASE	6,621	35.00	$231.7	6,621	50.00	$331.1
3 PHASE	74,319	60.00	$4,459.1	74,319	70.00	$5,202.3
SUBTOTAL	80,940		$4,690.8	80,940		$5,533.4
ADJUSTMENTS:						
POWER FACTOR ADJ.			($308.0)			($594.6)
TP VOLT. ADJ.			($84.6)			($98.3)
TS VOLT. ADJ.			($4.4)			($5.0)
DP VOLT. ADJ.			($403.0)			($779.2)
DS VOLT. ADJ.			($14.4)			($19.7)
NETWORK ADJ.			$0.0			$96.1
Schedule E Adjustment			$0.0			($264.5)
Schedule J - TOU Adjustment						$0.0
SUBTOTAL			($814.4)			($1,665.2)
UNADJUSTED BASE REVENUE			$209,880.4			$400,350.0
RATE RIDER & OTHER REVENUE ADJ.						
RIDER M(B)			($152.5)			($246.3)
RIDER I			($45.8)			($94.3)
RIDER T			($338.4)			($574.5)
MULTIPLE RIDERS			($247.5)			($486.9)
SCHEDULE U			($325.4)			($360.3)
Total Rate Rider & Other Revenue Adjustments			($1,109.6)			($1,762.3)
Total Base Revenue			$208,770.8			$398,587.7
Fuel Oil Adjustment	¢/kWh	7.299	$151,001.7		-	$0.0
Rate Adjustment (AES Refund)	%	-0.406%	($847.6)		-	$0.0
TOTAL REVENUE			$358,924.9			$398,587.7
INTERIM RATE INCREASE REVENUES			$13,361.3			$0.0
TOTAL REVENUE AT CURRENT EFFECTIVE RATES			$372,286.2			$398,587.7

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 2006-0386, Test-Year 2007
SCHEDULE H - COMMERCIAL COOKING, HEATING, AIR
CONDITIONING AND REFRIGERATION SERVICE

ESTIMATE OF TEST YEAR REVENUES

		PRESENT RATES			PROPOSED RATES		
	BILLING UNITS	UNIT PRICE		REVENUES $1000S	UNIT PRICE		REVENUES $1000S
	MWH	¢/kWh			¢/kWh		
ENERGY CHARGE:	40,500	7.7422		$3,135.6	16.5324		$6,695.6
	kW	$/kW			$/KW		
DEMAND CHARGE:	74,222	9.00		$668.0	10.00		$742.2
CUSTOMER CHARGE:	BILLS	$/month			$/month		
1 PHASE	2,721	20.00		$54.4	25.00		$68.0
3 PHASE	6,231	45.00		$280.4	60.00		$373.9
SUBTOTAL	8,952			$334.8			$441.9
SCHEDULE E ADJUSTMENT				$0.0			($6.0)
TOTAL BASE REVENUE				$4,138.4			$7,873.7
ADJUSTMENTS		Rate			Rate		
FUEL OIL ADJUSTMENT:		7.299	¢/KWH	$2,956.1	-	¢/KWH	$0.0
RATE ADJUSTMENT (AES REFUND):		(0.406)	(%)	($16.8)	-	(%)	$0.0
UNADJUSTED TOTAL REVENUE				$7,077.7			$7,873.7
RIDER ADJUSTMENTS				$0.0			$0.0
TOTAL REVENUES				$7,077.7			$7,873.7
INTERIM RATE INCREASE REVENUES				$276.4			$0.0
TOTAL REVENUE AT CURRENT EFFECTIVE RATES				$7,354.1			$7,873.7

HAWAIIAN ELECTRIC COMPANY, INC.
SCHEDULE PS - LARGE POWER SECONDARY VOLTAGE SERVICE
DOCKET NO. 2006-0386 TEST-YEAR: 2007

ESTIMATE OF TEST YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
ENERGY CHARGE:	(MWH)	¢/kWh		¢/kWh	
0 - 200 KWH/KW	366,774	7.2087	$26,439.6	14.1560	$51,920.5
201 - 400 KWH/KW	338,271	6.4104	$21,684.5	13.3577	$45,185.2
> 400 KWH/KW	130,812	6.1010	$7,980.8	13.0485	$17,069.0
SUBTOTAL	835,857		$56,104.9		$114,174.7
DEMAND CHARGE:	(kW)	$/kW		$/kW	
0 - 500 KW	1,034,937	10.00	$10,349.4	20.00	$20,698.7
501 - 1500 KW	479,646	9.50	$4,556.6	19.50	$9,353.1
> 1500 KW	367,120	8.50	$3,120.5	18.50	$6,791.7
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SUBTOTAL	1,881,703		$18,026.5		$36,843.5
	BILLS	$/month		$/month	
CUSTOMER CHARGE:	2,303	320.00	$737.0	350.00	$806.1
ADJUSTMENTS:					
POWER FACTOR ADJ.			($593.1)		($1,208.1)
NETWORK ADJ.			$127.0		$259.0
Schedule E Adjustment			$0.0		($91.7)
SUBTOTAL			($466.1)		($1,040.8)
UNADJUSTED BASE REVENUE			$74,402.3		$150,783.5
RATE RIDER & OTHER REVENUE ADJ.					
RIDER M (B)			($48.4)		($90.0)
RIDER I			$0.0		$0.0
RIDER T			($1.7)		($2.4)
RULE 4 CHP CONTRACTS ADJ.			$0.0		$0.0
Total Rate Rider & Other Revenue Adjustments			($50.1)		($92.4)
TOTAL BASE REVENUE			$74,352.2		$150,691.1
Fuel Oil Adjustment	¢/kWh	7.299	$61,009.2	-	$0.0
Rate Adjustment (AES Refund)	%	-0.406%	($301.9)	-	$0.0
TOTAL REVENUE			$135,059.5		$150,691.1
INTERIM RATE INCREASE REVENUES			$5,687.9		$0.0
TOTAL REVENUE AT CURRENT EFFECTIVE RATES			$140,747.4		$150,691.1

HAWAIIAN ELECTRIC COMPANY, INC.
SCHEDULE PP - LARGE POWER PRIMARY VOLTAGE SERVICE
DOCKET NO. 2006-0386 TEST-YEAR: 2007

ESTIMATE OF TEST YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
ENERGY CHARGE:	(MWH)	¢/kWh		¢/kWh	
0 - 200 KWH/KW	797,782	7.0715	$56,415.2	14.5773	$116,295.1
201 - 400 KWH/KW	744,994	6.2884	$46,848.2	13.7944	$102,767.5
> 400 KWH/KW	519,207	5.9849	$31,074.0	13.4907	$70,044.7
SUBTOTAL	2,061,983		$134,337.4		$289,107.3
DEMAND CHARGE:	(kW)	$/kW		$/kW	
0 - 500 KW	924,187	9.81	$9,066.3	18.50	$17,097.5
501 - 1500 KW	899,626	9.32	$8,384.5	18.00	$16,193.3
> 1500 KW	2,339,193	8.34	$19,508.9	17.00	$39,766.3
SUBTOTAL	4,163,006		$36,959.7		$73,057.1
Billing Demand Credit	1,698,643			-1.75	($2,972.6)
	BILLS	$/month		$/month	
CUSTOMER CHARGE:	1,946	320.00	$622.7	400.00	$778.4
ADJUSTMENTS:	(MWH)	¢/kWh		¢/kWh	
POWER FACTOR ADJ.			($1,713.0)		($3,621.6)
SECONDARY METERING ADJ.	21,511	0.1081	$23.3	0.2825	$60.8
Schedule E Adjustment			$0.0		($204.8)
SUBTOTAL			($1,689.7)		($3,765.6)
UNADJUSTED BASE REVENUE			$170,230.1		$356,204.6
RATE RIDER & OTHER REVENUE ADJ.					
RIDER M (B)			($757.8)		($1,468.2)
RIDER I			($112.9)		($199.4)
MULTIPLE RIDERS			($72.8)		($129.5)
Total Rate Rider & Other Revenue Adjustments			($943.5)		($1,797.1)
Total Base Revenue			$169,286.6		$354,407.5
Fuel Oil Adjustment	¢/kWh	7.299	$150,504.1	-	$0.0
Rate Adjustment (AES Refund)	%	-0.406%	($687.3)	-	$0.0
TOTAL REVENUE			$319,103.4		$354,407.5
INTERIM RATE INCREASE REVENUES			$11,917.8		$0.0
TOTAL REVENUE AT CURRENT EFFECTIVE RATES			$331,021.2		$354,407.5

HAWAIIAN ELECTRIC COMPANY, INC.
SCHEDULE PT - LARGE POWER TRANSMISSION VOLTAGE SERVICE
DOCKET NO. 2006-0386 TEST-YEAR: 2007

ESTIMATE OF TEST-YEAR REVENUES

	BILLING UNITS	PRESENT RATES UNIT PRICE	PRESENT RATES REVENUES $1000S	PROPOSED RATES UNIT PRICE	PROPOSED RATES REVENUES $1000S
ENERGY CHARGE:	(MWH)	¢/kWH		¢/kWH	
0 - 200 KWH/KW	55,137	6.9708	$3,843.5	14.3519	$7,913.2
201 - 400 KWH/KW	52,510	6.1989	$3,255.0	13.5799	$7,130.8
> 400 KWH/KW	67,514	5.8997	$3,983.1	13.2809	$8,966.5
SUBTOTAL	175,161		$11,081.6		$24,010.5
DEMAND CHARGE:	(kW)	$/kW		$/kW	
0 - 500 KW	22,748	9.67	$220.0	16.25	$369.7
501 - 1500 KW	39,496	9.19	$363.0	15.75	$622.1
> 1500 KW	222,107	8.22	$1,825.7	14.75	$3,276.1
SUBTOTAL	284,351		$2,408.7		$4,267.9
	BILLS	$/month		$/month	
CUSTOMER CHARGE:	47	320.00	$15.0	400.00	$18.8
ADJUSTMENTS:					
POWER FACTOR ADJ.			($188.9)		($395.9)
SECONDARY METERING ADJ.			$0.0		$0.0
Schedule E Adjustment			$0.0		($13.8)
SUBTOTAL			($188.9)		($409.7)
UNADJUSTED BASE REVENUE			$13,316.4		$27,887.5
Fuel Oil Adjustment	¢/kWH	7.299	$12,785.0	-	$0.0
Rate Adjustment (AES Refund):	%	-0.406%	($54.1)	-	$0.0
UNADJUSTED TOTAL REVENUE			$26,047.3		$27,887.5
RATE RIDER & OTHER REVENUE ADJ.					
RIDER M (B)			$0.0		$0.0
RIDER I			$0.0		$0.0
RIDER T			$0.0		$0.0
MULTIPLE RIDERS			$0.0		$0.0
RIDER EDR			$0.0		$0.0
SCHEDULE CHP			$0.0		$0.0
Total Rate Rider & Other Revenue Adjustments			$0.0		$0.0
TOTAL REVENUES			$26,047.3		$27,887.5
INTERIM RATE INCREASE REVENUES			$0.0		$0.0
TOTAL REVENUE AT CURRENT EFFECTIVE RATES			$26,047.3		$27,887.5

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 2006-0386, Test-Year 2007
SCHEDULE F - PUBLIC STREET LIGHTING SERVICE
HIGHWAY LIGHTING, & PARK & PLAYGROUND FLOODLIGHTING

ESTIMATE OF TEST-YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
CUSTOMER CHARGE:	Bills	$/month		$/month	
Customers	5,244	0.00	$0.0	20.00	$104.9
ENERGY CHARGE:	MWH	¢/kWh		¢/kWh	
0 - 150 KWH/KW	17,464	12.7049	$2,218.8	22.0105	$3,843.9
> 150 KWH/KW	20,336	8.7309	$1,775.5	18.0368	$3,668.0
SUBTOTAL	37,800		$3,994.3		$7,511.9
ADJUSTMENTS:					
MINIMUM BILL			$0.7		$0.4
SCHEDULE E ADJUSTMENT			$0.0		($7.8)
SECONDARY METERING ADJUSTMENT:			$13.7		$19.4
SUBTOTAL			$14.4		$12.0
UNADJUSTED BASE REVENUE:			$4,008.7		$7,628.8
FUEL OIL ADJUSTMENT:		7.299 ¢/kWh	$2,759.0	- ¢/kWh	$0.0
RATE ADJUSTMENT (AES REFUND):		(0.406) (%)	($16.3)	- (%)	$0.0
UNADJUSTED TOTAL REVENUE			$6,751.4		$7,628.8
RIDER ADJUSTMENTS			$0.0		$0.0
TOTAL REVENUES			$6,751.4		$7,628.8
INTERIM RATE INCREASE REVENUES			$374.0		$0.0
TOTAL REVENUE AT CURRENT EFFECTIVE RATES			$7,125.4		$7,628.8

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE

SINGLE PHASE

KWH	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase %
100	$25.53	$27.79	$2.26	8.85%
200	$44.07	$47.58	$3.51	7.96%
300	$62.62	$67.38	$4.76	7.60%
400	$81.17	$87.81	$6.64	8.18%
500	$99.72	$108.90	$9.18	9.21%
600	$118.26	$129.99	$11.73	9.92%
700	$136.81	$151.08	$14.27	10.43%
800	$155.35	$172.17	$16.82	10.83%
900	$173.91	$193.26	$19.35	11.13%
1,000	$192.45	$214.35	$21.90	11.38%
1,100	$211.01	$235.44	$24.43	11.58%
1,200	$229.55	$256.53	$26.98	11.75%
1,300	$248.11	$278.51	$30.40	12.25%
1,400	$266.66	$300.49	$33.83	12.69%
1,500	$285.20	$322.48	$37.28	13.07%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@present rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@present rates = -.406%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE

THREE PHASE

KWH	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase %
100	$33.49	$36.79	$3.30	9.85%
200	$52.04	$56.58	$4.54	8.72%
300	$70.59	$76.38	$5.79	8.20%
400	$89.14	$96.81	$7.67	8.60%
500	$107.69	$117.90	$10.21	9.48%
600	$126.22	$138.99	$12.77	10.12%
700	$144.78	$160.08	$15.30	10.57%
800	$163.32	$181.17	$17.85	10.93%
900	$181.88	$202.26	$20.38	11.21%
1,000	$200.42	$223.35	$22.93	11.44%
1,100	$218.97	$244.44	$25.47	11.63%
1,200	$237.52	$265.53	$28.01	11.79%
1,300	$256.07	$287.51	$31.44	12.28%
1,400	$274.63	$309.49	$34.86	12.69%
1,500	$293.17	$331.48	$38.31	13.07%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
    @present rates = 7.299 ¢/kWh
    @ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
    @present rates = -.406%
    @proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE, NON-DEMAND

SINGLE PHASE

KWH	Present Rate $/Mo.	Proposed Rate $/Mo.	Increase $/Mo.	Increase %
100	$38.33	$49.94	$11.61	30.29%
200	$56.74	$69.88	$13.14	23.16%
300	$75.15	$89.82	$14.67	19.52%
400	$93.57	$109.76	$16.19	17.30%
500	$111.98	$129.70	$17.72	15.82%
600	$130.38	$149.64	$19.26	14.77%
700	$148.79	$169.58	$20.79	13.97%
800	$167.21	$189.51	$22.30	13.34%
900	$185.61	$209.45	$23.84	12.84%
1,000	$204.03	$229.39	$25.36	12.43%
2,000	$388.13	$428.79	$40.66	10.48%
3,000	$572.24	$628.18	$55.94	9.78%
4,000	$756.35	$827.57	$71.22	9.42%
5,000	$940.45	$1,026.97	$86.52	9.20%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
  @present rates = 7.299 ¢/kWh
  @ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
  @present rates = -.406%
  @proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE, NON-DEMAND

THREE PHASE

KWH	Present Rate $/Mo.	Proposed Rate $/Mo.	Increase $/Mo.	Increase %
100	$63.23	$74.94	$11.71	18.52%
200	$81.64	$94.88	$13.24	16.22%
300	$100.05	$114.82	$14.77	14.76%
400	$118.47	$134.76	$16.29	13.75%
500	$136.88	$154.70	$17.82	13.02%
600	$155.28	$174.64	$19.36	12.47%
700	$173.69	$194.58	$20.89	12.03%
800	$192.10	$214.51	$22.41	11.67%
900	$210.51	$234.45	$23.94	11.37%
1,000	$228.92	$254.39	$25.47	11.13%
2,000	$413.03	$453.79	$40.76	9.87%
3,000	$597.14	$653.18	$56.04	9.38%
4,000	$781.25	$852.57	$71.32	9.13%
5,000	$965.35	$1,051.97	$86.62	8.97%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@present rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@present rates = -.406%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND

SINGLE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
25	2,500	100	$576.87	$743.53	$166.66	28.89%
25	5,000	200	$975.71	$1,137.05	$161.34	16.54%
25	10,000	400	$1,716.23	$1,866.70	$150.47	8.77%
25	12,500	500	$2,060.87	$2,205.79	$144.92	7.03%
25	15,000	600	$2,405.51	$2,544.89	$139.39	5.79%
50	5,000	100	$1,118.88	$1,437.05	$318.17	28.44%
50	10,000	200	$1,916.56	$2,224.10	$307.54	16.05%
50	20,000	400	$3,397.59	$3,683.39	$285.80	8.41%
50	25,000	500	$4,086.87	$4,361.59	$274.72	6.72%
50	30,000	600	$4,776.15	$5,039.78	$263.63	5.52%
100	10,000	100	$2,202.90	$2,824.10	$621.20	28.20%
100	20,000	200	$3,798.27	$4,398.20	$599.93	15.79%
100	40,000	400	$6,760.32	$7,316.78	$556.46	8.23%
100	50,000	500	$8,138.88	$8,673.17	$534.29	6.56%
100	60,000	600	$9,517.43	$10,029.56	$512.13	5.38%
300	30,000	100	$6,538.97	$8,372.30	$1,833.33	28.04%
300	60,000	200	$11,325.09	$13,094.60	$1,769.51	15.62%
300	120,000	400	$20,211.25	$21,850.34	$1,639.09	8.11%
300	150,000	500	$24,346.92	$25,919.51	$1,572.59	6.46%
300	180,000	600	$28,482.59	$29,988.68	$1,506.09	5.29%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@present rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@present rates = -.406%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND

THREE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
25	2,500	100	$601.77	$763.53	$161.76	26.88%
25	5,000	200	$1,000.61	$1,157.05	$156.44	15.63%
25	10,000	400	$1,741.13	$1,886.70	$145.57	8.36%
25	12,500	500	$2,085.77	$2,225.79	$140.02	6.71%
25	15,000	600	$2,430.41	$2,564.89	$134.49	5.53%
50	5,000	100	$1,143.78	$1,457.05	$313.27	27.39%
50	10,000	200	$1,941.46	$2,244.10	$302.64	15.59%
50	20,000	400	$3,422.49	$3,703.39	$280.90	8.21%
50	25,000	500	$4,111.77	$4,381.59	$269.82	6.56%
50	30,000	600	$4,801.04	$5,059.78	$258.74	5.39%
100	10,000	100	$2,227.79	$2,844.10	$616.31	27.66%
100	20,000	200	$3,823.17	$4,418.20	$595.03	15.56%
100	40,000	400	$6,785.22	$7,336.78	$551.56	8.13%
100	50,000	500	$8,163.78	$8,693.17	$529.39	6.48%
100	60,000	600	$9,542.33	$10,049.56	$507.23	5.32%
300	30,000	100	$6,563.87	$8,392.30	$1,828.43	27.86%
300	60,000	200	$11,349.98	$13,114.60	$1,764.62	15.55%
300	120,000	400	$20,236.15	$21,870.34	$1,634.19	8.08%
300	150,000	500	$24,371.82	$25,939.51	$1,567.69	6.43%
300	180,000	600	$28,507.49	$30,008.68	$1,501.19	5.27%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@present rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@present rates = -.406%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING, A/C, & REFRIGERATION SERVICES

SINGLE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
10	1,000	100	$259.65	$290.32	$30.67	11.81%
10	2,000	200	$409.74	$455.65	$45.91	11.20%
10	3,000	300	$559.85	$620.97	$61.12	10.92%
10	4,000	400	$709.95	$786.30	$76.35	10.75%
25	2,500	100	$619.26	$688.31	$69.05	11.15%
25	5,000	200	$994.49	$1,101.62	$107.13	10.77%
25	7,500	300	$1,369.75	$1,514.93	$145.18	10.60%
25	10,000	400	$1,744.98	$1,928.24	$183.26	10.50%
50	5,000	100	$1,218.58	$1,351.62	$133.04	10.92%
50	10,000	200	$1,969.07	$2,178.24	$209.17	10.62%
50	15,000	300	$2,719.56	$3,004.86	$285.30	10.49%
50	20,000	400	$3,470.05	$3,831.48	$361.43	10.42%
100	10,000	100	$2,417.24	$2,678.24	$261.00	10.80%
100	20,000	200	$3,918.22	$4,331.48	$413.26	10.55%
100	30,000	300	$5,419.19	$5,984.72	$565.53	10.44%
100	40,000	400	$6,920.17	$7,637.96	$717.79	10.37%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@present rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@present rates = -.406%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING, A/C, & REFRIGERATION SERVICES

THREE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
10	1,000	100	$284.55	$325.32	$40.77	14.33%
10	2,000	200	$434.64	$490.65	$56.01	12.89%
10	3,000	300	$584.75	$655.97	$71.22	12.18%
10	4,000	400	$734.84	$821.30	$86.46	11.77%
25	2,500	100	$644.16	$723.31	$79.15	12.29%
25	5,000	200	$1,019.39	$1,136.62	$117.23	11.50%
25	7,500	300	$1,394.65	$1,549.93	$155.28	11.13%
25	10,000	400	$1,769.88	$1,963.24	$193.36	10.93%
50	5,000	100	$1,243.48	$1,386.62	$143.14	11.51%
50	10,000	200	$1,993.97	$2,213.24	$219.27	11.00%
50	15,000	300	$2,744.46	$3,039.86	$295.40	10.76%
50	20,000	400	$3,494.94	$3,866.48	$371.54	10.63%
100	10,000	100	$2,442.14	$2,713.24	$271.10	11.10%
100	20,000	200	$3,943.12	$4,366.48	$423.36	10.74%
100	30,000	300	$5,444.09	$6,019.72	$575.63	10.57%
100	40,000	400	$6,945.07	$7,672.96	$727.89	10.48%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@present rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@present rates = -.406%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE PS: LARGE POWER SECONDARY VOLTAGE SERVICE

KW	MWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
300	60	200	$11,993.58	$14,843.60	$2,850.02	23.76%
300	120	400	$20,203.60	$22,858.22	$2,654.62	13.14%
300	150	500	$24,216.17	$26,772.77	$2,556.60	10.56%
300	180	600	$28,228.74	$30,687.32	$2,458.58	8.71%
300	210	700	$32,241.31	$34,601.87	$2,360.56	7.32%
500	100	200	$19,776.83	$24,506.00	$4,729.17	23.91%
500	200	400	$33,460.21	$37,863.70	$4,403.49	13.16%
500	250	500	$40,147.82	$44,387.95	$4,240.13	10.56%
500	300	600	$46,835.44	$50,912.20	$4,076.76	8.70%
500	350	700	$53,523.05	$57,436.45	$3,913.40	7.31%
1,500	300	200	$58,195.13	$72,318.00	$14,122.87	24.27%
1,500	600	400	$99,245.25	$112,391.10	$13,145.85	13.25%
1,500	750	500	$119,308.10	$131,963.85	$12,655.75	10.61%
1,500	900	600	$139,370.94	$151,536.60	$12,165.66	8.73%
1,500	1,050	700	$159,433.78	$171,109.35	$11,675.57	7.32%
5,000	1,000	200	$189,173.37	$236,160.00	$46,986.63	24.84%
5,000	2,000	400	$326,007.11	$369,737.00	$43,729.89	13.41%
5,000	2,500	500	$392,883.26	$434,979.50	$42,096.24	10.71%
5,000	3,000	600	$459,759.41	$500,222.00	$40,462.59	8.80%
5,000	3,500	700	$526,635.56	$565,464.50	$38,828.94	7.37%
10,000	2,000	200	$376,285.15	$470,220.00	$93,934.85	24.96%
10,000	4,000	400	$649,952.62	$737,374.00	$87,421.38	13.45%
10,000	5,000	500	$783,704.92	$867,859.00	$84,154.08	10.74%
10,000	6,000	600	$917,457.22	$998,344.00	$80,886.78	8.82%
10,000	7,000	700	$1,051,209.52	$1,128,829.00	$77,619.48	7.38%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@present rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@present rates = -.406%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE PP: LARGE POWER PRIMARY VOLTAGE SERVICE

KW	MWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
300	60	200	$11,854.83	$14,696.38	$2,841.55	23.97%
300	120	400	$19,991.95	$22,973.02	$2,981.07	14.91%
300	150	500	$23,969.83	$27,020.23	$3,050.40	12.73%
300	180	600	$27,947.71	$31,067.44	$3,119.73	11.16%
300	210	700	$31,925.59	$35,114.65	$3,189.06	9.99%
500	100	200	$19,545.58	$24,227.30	$4,681.72	23.95%
500	200	400	$33,107.45	$38,021.70	$4,914.25	14.84%
500	250	500	$39,737.25	$44,767.05	$5,029.80	12.66%
500	300	600	$46,367.05	$51,512.40	$5,145.35	11.10%
500	350	700	$52,996.85	$58,257.75	$5,260.90	9.93%
1,500	300	200	$57,511.32	$71,381.90	$13,870.58	24.12%
1,500	600	400	$98,196.92	$112,765.10	$14,568.18	14.84%
1,500	750	500	$118,086.33	$133,001.15	$14,914.82	12.63%
1,500	900	600	$137,975.73	$153,237.20	$15,261.47	11.06%
1,500	1,050	700	$157,865.13	$173,473.25	$15,608.12	9.89%
5,000	1,000	200	$186,975.33	$232,923.00	$45,947.67	24.57%
5,000	2,000	400	$322,594.02	$370,867.00	$48,272.98	14.96%
5,000	2,500	500	$388,892.03	$438,320.50	$49,428.47	12.71%
5,000	3,000	600	$455,190.04	$505,774.00	$50,583.96	11.11%
5,000	3,500	700	$521,488.04	$573,227.50	$51,739.46	9.92%
10,000	2,000	200	$371,923.93	$463,696.00	$91,772.07	24.67%
10,000	4,000	400	$643,161.31	$739,584.00	$96,422.69	14.99%
10,000	5,000	500	$775,757.32	$874,491.00	$98,733.68	12.73%
10,000	6,000	600	$908,353.34	$1,009,398.00	$101,044.66	11.12%
10,000	7,000	700	$1,040,949.35	$1,144,305.00	$103,355.65	9.93%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@present rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@present rates = -.406%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE PT: LARGE POWER TRANSMISSION VOLTAGE SERVICE

KW	MWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
300	60	200	$11,752.82	$13,886.14	$2,133.32	18.15%
300	120	400	$19,836.46	$22,034.08	$2,197.62	11.08%
300	150	500	$23,788.89	$26,018.35	$2,229.46	9.37%
300	180	600	$27,741.31	$30,002.62	$2,261.31	8.15%
300	210	700	$31,693.73	$33,986.89	$2,293.16	7.24%
500	100	200	$19,375.57	$22,876.90	$3,501.33	18.07%
500	200	400	$32,848.30	$36,456.80	$3,608.50	10.99%
500	250	500	$39,435.68	$43,097.25	$3,661.57	9.28%
500	300	600	$46,023.05	$49,737.70	$3,714.65	8.07%
500	350	700	$52,610.42	$56,378.15	$3,767.73	7.16%
1,500	300	200	$57,011.25	$67,330.70	$10,319.45	18.10%
1,500	600	400	$97,429.45	$108,070.40	$10,640.95	10.92%
1,500	750	500	$117,191.57	$127,991.75	$10,800.18	9.22%
1,500	900	600	$136,953.69	$147,913.10	$10,959.41	8.00%
1,500	1,050	700	$156,715.81	$167,834.45	$11,118.64	7.09%
5,000	1,000	200	$185,354.94	$219,419.00	$34,064.06	18.38%
5,000	2,000	400	$320,082.26	$355,218.00	$35,135.74	10.98%
5,000	2,500	500	$385,956.00	$421,622.50	$35,666.50	9.24%
5,000	3,000	600	$451,829.74	$488,027.00	$36,197.26	8.01%
5,000	3,500	700	$517,703.47	$554,431.50	$36,728.03	7.09%
10,000	2,000	200	$368,703.06	$436,688.00	$67,984.94	18.44%
10,000	4,000	400	$638,157.71	$708,286.00	$70,128.29	10.99%
10,000	5,000	500	$769,905.18	$841,095.00	$71,189.82	9.25%
10,000	6,000	600	$901,652.65	$973,904.00	$72,251.35	8.01%
10,000	7,000	700	$1,033,400.12	$1,106,713.00	$73,312.88	7.09%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@present rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@present rates = -.406%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE F: PUBLIC STREET LIGHTING, HIGHWAY LIGHTING, AND PARK AND PLAYGROUND LIGHTING

KW	KWH	KWH/KW	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase (%)
1	150	150	$34.86	$53.02	$18.16	52.08%
1	340	340	$60.32	$87.29	$26.97	44.71%
5	750	150	$149.64	$185.08	$35.44	23.68%
5	1,700	340	$301.59	$356.43	$54.84	18.18%
10	1,500	150	$299.28	$350.16	$50.87	17.00%
10	3,400	340	$603.18	$692.86	$89.68	14.87%
25	3,750	150	$748.21	$845.39	$97.18	12.99%
25	8,500	340	$1,507.95	$1,702.14	$194.19	12.88%
50	7,500	150	$1,496.42	$1,670.79	$174.36	11.65%
50	17,000	340	$3,015.90	$3,384.28	$368.39	12.21%
100	15,000	150	$2,992.85	$3,321.58	$328.73	10.98%
100	34,000	340	$6,031.79	$6,748.57	$716.77	11.88%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@present rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@present rates = -.406%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
CURRENT EFFECTIVE RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE

SINGLE PHASE

KWH	Current Effective Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase %
100	$26.73	$27.79	$1.06	3.97%
200	$46.01	$47.58	$1.57	3.41%
300	$65.31	$67.38	$2.07	3.17%
400	$84.59	$87.81	$3.22	3.81%
500	$103.90	$108.90	$5.00	4.81%
600	$123.17	$129.99	$6.82	5.54%
700	$142.47	$151.08	$8.61	6.04%
800	$161.76	$172.17	$10.41	6.44%
900	$181.05	$193.26	$12.21	6.74%
1,000	$200.34	$214.35	$14.01	6.99%
1,100	$219.63	$235.44	$15.81	7.20%
1,200	$238.92	$256.53	$17.61	7.37%
1,300	$258.21	$278.51	$20.30	7.86%
1,400	$277.52	$300.49	$22.97	8.28%
1,500	$296.80	$322.48	$25.68	8.65%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@current eff rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@current eff rates = -.406%
@proposed rates = 0.000%
Interim Rate Increase
@current effent rates = 6.60%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
CURRENT EFFECTIVE RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE

THREE PHASE

KWH	Current Effective Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase %
100	$35.23	$36.79	$1.56	4.43%
200	$54.51	$56.58	$2.07	3.80%
300	$73.81	$76.38	$2.57	3.48%
400	$93.09	$96.81	$3.72	4.00%
500	$112.39	$117.90	$5.51	4.90%
600	$131.66	$138.99	$7.33	5.57%
700	$150.96	$160.08	$9.12	6.04%
800	$170.24	$181.17	$10.93	6.42%
900	$189.55	$202.26	$12.71	6.71%
1,000	$208.83	$223.35	$14.52	6.95%
1,100	$228.13	$244.44	$16.31	7.15%
1,200	$247.42	$265.53	$18.11	7.32%
1,300	$266.71	$287.51	$20.80	7.80%
1,400	$286.01	$309.49	$23.48	8.21%
1,500	$305.29	$331.48	$26.19	8.58%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@current eff rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@current eff rates = -.406%
@proposed rates = 0.000%
Interim Rate Increase
@current effent rates = 6.60%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
CURRENT EFFECTIVE RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE, NON-DEMAND

SINGLE PHASE

KWH	Current Effective Rates $/Mo.	Proposed Rate $/Mo.	Increase $/Mo.	Increase %
100	$40.19	$49.94	$9.75	24.26%
200	$59.26	$69.88	$10.62	17.92%
300	$78.33	$89.82	$11.49	14.67%
400	$97.41	$109.76	$12.35	12.68%
500	$116.48	$129.70	$13.22	11.35%
600	$135.55	$149.64	$14.09	10.39%
700	$154.63	$169.58	$14.95	9.67%
800	$173.70	$189.51	$15.81	9.10%
900	$192.77	$209.45	$16.68	8.65%
1,000	$211.84	$229.39	$17.55	8.28%
2,000	$402.59	$428.79	$26.20	6.51%
3,000	$593.33	$628.18	$34.85	5.87%
4,000	$784.07	$827.57	$43.50	5.55%
5,000	$974.81	$1,026.97	$52.16	5.35%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@current eff rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@current eff rates = -.406%
@proposed rates = 0.000%
Interim Rate Increase
@current effent rates = 5.97%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
CURRENT EFFECTIVE RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE, NON-DEMAND

THREE PHASE

KWH	Current Effective Rates $/Mo.	Proposed Rate $/Mo.	Increase $/Mo.	Increase %
100	$66.57	$74.94	$8.37	12.57%
200	$85.64	$94.88	$9.24	10.79%
300	$104.71	$114.82	$10.11	9.66%
400	$123.79	$134.76	$10.97	8.86%
500	$142.88	$154.70	$11.82	8.27%
600	$161.93	$174.64	$12.71	7.85%
700	$181.01	$194.58	$13.57	7.50%
800	$200.09	$214.51	$14.42	7.21%
900	$219.15	$234.45	$15.30	6.98%
1,000	$238.24	$254.39	$16.15	6.78%
2,000	$428.98	$453.79	$24.81	5.78%
3,000	$619.72	$653.18	$33.46	5.40%
4,000	$810.46	$852.57	$42.11	5.20%
5,000	$1,001.20	$1,051.97	$50.77	5.07%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@current eff rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@current eff rates = -.406%
@proposed rates = 0.000%
Interim Rate Increase
@current effent rates = 5.97%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
CURRENT EFFECTIVE RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND

SINGLE PHASE

KW	KWH	KWH/KW	Current Effective Rates $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
25	2,500	100	$602.11	$743.53	$141.42	23.49%
25	5,000	200	$975.71	$1,137.05	$161.34	16.54%
25	10,000	400	$1,716.23	$1,866.70	$150.47	8.77%
25	12,500	500	$2,060.87	$2,205.79	$144.92	7.03%
25	15,000	600	$2,405.51	$2,544.89	$139.39	5.79%
50	5,000	100	$1,118.88	$1,437.05	$318.17	28.44%
50	10,000	200	$1,916.56	$2,224.10	$307.54	16.05%
50	20,000	400	$3,397.59	$3,683.39	$285.80	8.41%
50	25,000	500	$4,086.87	$4,361.59	$274.72	6.72%
50	30,000	600	$4,776.15	$5,039.78	$263.63	5.52%
100	10,000	100	$2,202.90	$2,824.10	$621.20	28.20%
100	20,000	200	$3,798.27	$4,398.20	$599.93	15.79%
100	40,000	400	$6,760.32	$7,316.78	$556.46	8.23%
100	50,000	500	$8,138.88	$8,673.17	$534.29	6.56%
100	60,000	600	$9,517.43	$10,029.56	$512.13	5.38%
300	30,000	100	$6,538.97	$8,372.30	$1,833.33	28.04%
300	60,000	200	$11,325.09	$13,094.60	$1,769.51	15.62%
300	120,000	400	$20,211.25	$21,850.34	$1,639.09	8.11%
300	150,000	500	$24,346.92	$25,919.51	$1,572.59	6.46%
300	180,000	600	$28,482.59	$29,988.68	$1,506.09	5.29%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@current eff rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@current eff rates = -.406%
@proposed rates = 0.000%
Interim Rate Increase
@current effent rates = 6.40%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
CURRENT EFFECTIVE RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND

THREE PHASE

KW	KWH	KWH/KW	Current Effective Rates $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
25	2,500	100	$628.60	$763.53	$134.93	21.46%
25	5,000	200	$1,041.29	$1,157.05	$115.76	11.12%
25	10,000	400	$1,805.84	$1,886.70	$80.86	4.48%
25	12,500	500	$2,160.86	$2,225.79	$64.93	3.00%
25	15,000	600	$2,515.88	$2,564.89	$49.01	1.95%
50	5,000	100	$1,193.62	$1,457.05	$263.43	22.07%
50	10,000	200	$2,019.00	$2,244.10	$225.10	11.15%
50	20,000	400	$3,548.10	$3,703.39	$155.29	4.38%
50	25,000	500	$4,258.14	$4,381.59	$123.45	2.90%
50	30,000	600	$4,968.17	$5,059.78	$91.61	1.84%
100	10,000	100	$2,323.66	$2,844.10	$520.44	22.40%
100	20,000	200	$3,974.42	$4,418.20	$443.78	11.17%
100	40,000	400	$7,032.62	$7,336.78	$304.16	4.32%
100	50,000	500	$8,452.69	$8,693.17	$240.48	2.85%
100	60,000	600	$9,872.76	$10,049.56	$176.80	1.79%
300	30,000	100	$6,843.82	$8,392.30	$1,548.48	22.63%
300	60,000	200	$11,796.11	$13,114.60	$1,318.49	11.18%
300	120,000	400	$20,970.70	$21,870.34	$899.64	4.29%
300	150,000	500	$25,230.91	$25,939.51	$708.60	2.81%
300	180,000	600	$29,491.12	$30,008.68	$517.56	1.75%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@current eff rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@current eff rates = -.406%
@proposed rates = 0.000%
Interim Rate Increase
@current effent rates = 6.40%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
CURRENT EFFECTIVE RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING, A/C, & REFRIGERATION SERVICES

SINGLE PHASE

KW	KWH	KWH/KW	Current Effective Rates $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
10	1,000	100	$272.12	$290.32	$18.20	6.69%
10	2,000	200	$427.36	$455.65	$28.29	6.62%
10	3,000	300	$582.62	$620.97	$38.35	6.58%
10	4,000	400	$737.87	$786.30	$48.43	6.56%
25	2,500	100	$648.44	$688.31	$39.87	6.15%
25	5,000	200	$1,036.54	$1,101.62	$65.08	6.28%
25	7,500	300	$1,424.67	$1,514.93	$90.26	6.34%
25	10,000	400	$1,812.79	$1,928.24	$115.45	6.37%
50	5,000	100	$1,275.60	$1,351.62	$76.02	5.96%
50	10,000	200	$2,051.84	$2,178.24	$126.40	6.16%
50	15,000	300	$2,828.08	$3,004.86	$176.78	6.25%
50	20,000	400	$3,604.33	$3,831.48	$227.15	6.30%
100	10,000	100	$2,529.95	$2,678.24	$148.29	5.86%
100	20,000	200	$4,082.44	$4,331.48	$249.04	6.10%
100	30,000	300	$5,634.93	$5,984.72	$349.79	6.21%
100	40,000	400	$7,187.41	$7,637.96	$450.55	6.27%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@current eff rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@current eff rates = -.406%
@proposed rates = 0.000%
Interim Rate Increase
@current effent rates = 6.68%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
CURRENT EFFECTIVE RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING, A/C, & REFRIGERATION SERVICES

THREE PHASE

KW	KWH	KWH/KW	Current Effective Rates $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
10	1,000	100	$298.68	$325.32	$26.64	8.92%
10	2,000	200	$453.92	$490.65	$36.73	8.09%
10	3,000	300	$609.18	$655.97	$46.79	7.68%
10	4,000	400	$764.43	$821.30	$56.87	7.44%
25	2,500	100	$675.00	$723.31	$48.31	7.16%
25	5,000	200	$1,063.10	$1,136.62	$73.52	6.92%
25	7,500	300	$1,451.24	$1,549.93	$98.69	6.80%
25	10,000	400	$1,839.35	$1,963.24	$123.89	6.74%
50	5,000	100	$1,302.16	$1,386.62	$84.46	6.49%
50	10,000	200	$2,078.40	$2,213.24	$134.84	6.49%
50	15,000	300	$2,854.65	$3,039.86	$185.21	6.49%
50	20,000	400	$3,630.89	$3,866.48	$235.59	6.49%
100	10,000	100	$2,556.51	$2,713.24	$156.73	6.13%
100	20,000	200	$4,109.00	$4,366.48	$257.48	6.27%
100	30,000	300	$5,661.49	$6,019.72	$358.23	6.33%
100	40,000	400	$7,213.97	$7,672.96	$458.99	6.36%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@current eff rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@current eff rates = -.406%
@proposed rates = 0.000%
Interim Rate Increase
@current effent rates = 6.68%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
CURRENT EFFECTIVE RATES & PROPOSED RATES
SCHEDULE PS: LARGE POWER SECONDARY VOLTAGE SERVICE

KW	MWH	KWH/KW	Current Effective Rates $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
300	60	200	$12,576.07	$14,843.60	$2,267.53	18.03%
300	120	400	$21,079.14	$22,858.22	$1,779.08	8.44%
300	150	500	$25,231.15	$26,772.77	$1,541.62	6.11%
300	180	600	$29,383.17	$30,687.32	$1,304.15	4.44%
300	210	700	$33,535.19	$34,601.87	$1,066.68	3.18%
500	100	200	$20,731.39	$24,506.00	$3,774.61	18.21%
500	200	400	$34,903.16	$37,863.70	$2,960.54	8.48%
500	250	500	$41,823.19	$44,387.95	$2,564.76	6.13%
500	300	600	$48,743.23	$50,912.20	$2,168.97	4.45%
500	350	700	$55,663.26	$57,436.45	$1,773.19	3.19%
1,500	300	200	$60,971.94	$72,318.00	$11,346.06	18.61%
1,500	600	400	$103,487.27	$112,391.10	$8,903.83	8.60%
1,500	750	500	$124,247.36	$131,963.85	$7,716.49	6.21%
1,500	900	600	$145,007.45	$151,536.60	$6,529.15	4.50%
1,500	1,050	700	$165,767.54	$171,109.35	$5,341.81	3.22%
5,000	1,000	200	$198,061.40	$236,160.00	$38,098.60	19.24%
5,000	2,000	400	$339,779.19	$369,737.00	$29,957.81	8.82%
5,000	2,500	500	$408,979.49	$434,979.50	$26,000.01	6.36%
5,000	3,000	600	$478,179.80	$500,222.00	$22,042.20	4.61%
5,000	3,500	700	$547,380.10	$565,464.50	$18,084.40	3.30%
10,000	2,000	200	$393,903.50	$470,220.00	$76,316.50	19.37%
10,000	4,000	400	$677,339.06	$737,374.00	$60,034.94	8.86%
10,000	5,000	500	$815,739.67	$867,859.00	$52,119.33	6.39%
10,000	6,000	600	$954,140.29	$998,344.00	$44,203.71	4.63%
10,000	7,000	700	$1,092,540.90	$1,128,829.00	$36,288.10	3.32%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@current eff rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@current eff rates = -.406%
@proposed rates = 0.000%
Interim Rate Increase
@current effent rates = 7.65%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
CURRENT EFFECTIVE RATES & PROPOSED RATES
SCHEDULE PP: LARGE POWER PRIMARY VOLTAGE SERVICE

KW	MWH	KWH/KW	Current Effective Rates $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
300	60	200	$12,381.10	$14,696.38	$2,315.28	18.70%
300	120	400	$20,782.76	$22,973.02	$2,190.26	10.54%
300	150	500	$24,886.53	$27,020.23	$2,133.70	8.57%
300	180	600	$28,990.30	$31,067.44	$2,077.14	7.16%
300	210	700	$33,094.07	$35,114.65	$2,020.58	6.11%
500	100	200	$20,407.73	$24,227.30	$3,819.57	18.72%
500	200	400	$34,410.51	$38,021.70	$3,611.19	10.49%
500	250	500	$41,250.13	$44,767.05	$3,516.92	8.53%
500	300	600	$48,089.73	$51,512.40	$3,422.67	7.12%
500	350	700	$54,929.35	$58,257.75	$3,328.40	6.06%
1,500	300	200	$60,018.57	$71,381.90	$11,363.33	18.93%
1,500	600	400	$102,026.89	$112,765.10	$10,738.21	10.52%
1,500	750	500	$122,545.73	$133,001.15	$10,455.42	8.53%
1,500	900	600	$143,064.57	$153,237.20	$10,172.63	7.11%
1,500	1,050	700	$163,583.42	$173,473.25	$9,889.83	6.05%
5,000	1,000	200	$194,999.90	$232,923.00	$37,923.10	19.45%
5,000	2,000	400	$335,027.65	$370,867.00	$35,839.35	10.70%
5,000	2,500	500	$403,423.79	$438,320.50	$34,896.71	8.65%
5,000	3,000	600	$471,819.92	$505,774.00	$33,954.08	7.20%
5,000	3,500	700	$540,216.07	$573,227.50	$33,011.43	6.11%
10,000	2,000	200	$387,830.38	$463,696.00	$75,865.62	19.56%
10,000	4,000	400	$667,885.88	$739,584.00	$71,698.12	10.74%
10,000	5,000	500	$804,678.16	$874,491.00	$69,812.84	8.68%
10,000	6,000	600	$941,470.43	$1,009,398.00	$67,927.57	7.22%
10,000	7,000	700	$1,078,262.71	$1,144,305.00	$66,042.29	6.12%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
  @current eff rates = 7.299 ¢/kWh
  @ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
  @current eff rates = -.406%
  @proposed rates = 0.000%
Interim Rate Increase
  @current effent rates = 7.04%
  @proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
CURRENT EFFECTIVE RATES & PROPOSED RATES
SCHEDULE PT: LARGE POWER TRANSMISSION VOLTAGE SERVICE

KW	MWH	KWH/KW	Current Effective Rates $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
300	60	200	$11,752.82	$13,886.14	$2,133.32	18.15%
300	120	400	$19,836.46	$22,034.08	$2,197.62	11.08%
300	150	500	$23,788.89	$26,018.35	$2,229.46	9.37%
300	180	600	$27,741.31	$30,002.62	$2,261.31	8.15%
300	210	700	$31,693.73	$33,986.89	$2,293.16	7.24%
500	100	200	$19,375.57	$22,876.90	$3,501.33	18.07%
500	200	400	$32,848.30	$36,456.80	$3,608.50	10.99%
500	250	500	$39,435.68	$43,097.25	$3,661.57	9.28%
500	300	600	$46,023.05	$49,737.70	$3,714.65	8.07%
500	350	700	$52,610.42	$56,378.15	$3,767.73	7.16%
1,500	300	200	$57,011.25	$67,330.70	$10,319.45	18.10%
1,500	600	400	$97,429.45	$108,070.40	$10,640.95	10.92%
1,500	750	500	$117,191.57	$127,991.75	$10,800.18	9.22%
1,500	900	600	$136,953.69	$147,913.10	$10,959.41	8.00%
1,500	1,050	700	$156,715.81	$167,834.45	$11,118.64	7.09%
5,000	1,000	200	$185,354.94	$219,419.00	$34,064.06	18.38%
5,000	2,000	400	$320,082.26	$355,218.00	$35,135.74	10.98%
5,000	2,500	500	$385,956.00	$421,622.50	$35,666.50	9.24%
5,000	3,000	600	$451,829.74	$488,027.00	$36,197.26	8.01%
5,000	3,500	700	$517,703.47	$554,431.50	$36,728.03	7.09%
10,000	2,000	200	$368,703.06	$436,688.00	$67,984.94	18.44%
10,000	4,000	400	$638,157.71	$708,286.00	$70,128.29	10.99%
10,000	5,000	500	$769,905.18	$841,095.00	$71,189.82	9.25%
10,000	6,000	600	$901,652.65	$973,904.00	$72,251.35	8.01%
10,000	7,000	700	$1,033,400.12	$1,106,713.00	$73,312.88	7.09%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@current eff rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@current eff rates = -.406%
@proposed rates = 0.000%
Interim Rate Increase
@current effent rates = 0.000%
@proposed rates = 0.000%

HAWAIIAN ELECTRIC COMPANY, INC.

TEST YEAR: 2007, DOCKET NO: 2006-0386
BILL COMPARISONS UNDER
CURRENT EFFECTIVE RATES & PROPOSED RATES
SCHEDULE F: PUBLIC STREET LIGHTING, HIGHWAY LIGHTING, AND PARK AND PLAYGROUND LIGHTING

KW	KWH	KWH/KW	Current Effective Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase (%)
1	150	150	$38.11	$53.02	$14.91	39.11%
1	340	340	$63.63	$87.29	$23.66	37.18%
5	750	150	$158.50	$185.08	$26.58	16.77%
5	1,700	340	$318.15	$356.43	$38.28	12.03%
10	1,500	150	$316.99	$350.16	$33.17	10.46%
10	3,400	340	$636.31	$692.86	$56.55	8.89%
25	3,750	150	$792.49	$845.39	$52.90	6.68%
25	8,500	340	$1,590.76	$1,702.14	$111.38	7.00%
50	7,500	150	$1,584.97	$1,670.79	$85.82	5.41%
50	17,000	340	$3,181.51	$3,384.28	$202.77	6.37%
100	15,000	150	$3,169.93	$3,321.58	$151.65	4.78%
100	34,000	340	$6,363.02	$6,748.57	$385.55	6.06%

* Present Rates Effective January 1, 1997
Test -year 2007 FOA:
@current eff rates = 7.299 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 AES Refund:
@current eff rates = -.406%
@proposed rates = 0.000%
Interim Rate Increase
@current effent rates = 9.33%
@proposed rates = 0.000%

TESTIMONY OF
JEFF D. MAKHOLM, PH.D

On Behalf of
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Energy Cost Adjustment Clause

SECTION I: QUALIFICATIONS, PURPOSE, AND CONCLUSIONS

Q. Please state your name, business address and current position.

A. My name is Jeff D. Makholm. I am a Senior Vice President at National Economic Research Associates, Inc. ("NERA"). NERA is a firm of consulting economists with its principal offices in a number of major U.S. and European cities. My business address is 200 Clarendon Street, Boston, Massachusetts, 02116.

Q. Please describe your academic background.

A. I have M.A. and Ph.D degrees in economics from the University of Wisconsin, Madison, with a major field of Industrial Organization and a minor field of Econometrics/Public Economics. My 1986 Ph.D dissertation is entitled "Sources of Total Factor Productivity in the Electric Utility Industry." I also have B.A. and M.A. degrees in economics from the University of Wisconsin, Milwaukee. Prior to my latest full-time consulting activities, I was an Adjunct Professor in the Graduate School of Business at Northeastern University in Boston, Massachusetts, teaching courses in microeconomic theory and managerial economics.

Q. Please describe your work experience pertinent to this proceeding.

A. My work centers on economic issues involving pricing, regulation and market issues for regulated infrastructure industries, including gas, electricity, water and telecommunications utilities, gas and oil pipelines, airports, toll roads and passenger and freight railroads. My consulting work includes the specific issues of competition, rate design, fair rate of return, regulatory rulemaking, incentive ratemaking, load forecasting, least-cost planning, cost measurement, contract obligations and bankruptcy. I have prepared expert testimony and statements, and I have appeared as an expert witness in many state and federal administrative and United States District Court proceedings, as well as in regulatory and judicial hearings abroad.

I have also directed studies on behalf of utility companies, governments and the World Bank in many countries. In these countries, I have drafted regulations, established tariffs, recommended financing options for major capital projects and advised on industry restructurings. I have also assisted in the privatization of state-owned gas utilities. As part of my international work, I have conducted formal training sessions for government, industry and regulatory personnel on the subjects of privatization, pricing, finance and regulation of the gas industry.

Over the past 25 years I have presented evidence on many ratemaking subjects, including the pass-through of fuel, purchased power and gas costs. For example, in 2005, I prepared testimony on the role of fuel adjustment clauses ("FACs") and related financial issues for Portland General Electric as well as a report summarizing the current state of FACs in the United States. I have testified on numerous occasions recently on behalf of Sierra Pacific Power Company and Nevada Power Company with respect to their natural gas hedging programs and related cost recovery. Overall, I have testified for electric, natural gas, water and telecommunications clients before the Federal Energy Regulatory Commission (the "FERC"), the Federal Communication Commission (the "FCC") and state commissions in Pennsylvania, Oregon, Ohio, North Carolina, Kansas, Illinois, New Jersey, New York, Maryland, California, Virginia, Rhode Island, New Hampshire, Texas, Indiana, Maine, Nevada, Wisconsin, Georgia and Connecticut.

My current Curriculum Vitae, which more fully details my educational and consulting experience, is provided as **Exhibit HECO - 2100**.

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by Hawaiian Electric Company, Inc. ("HECO") to provide testimony explaining the role of fuel adjustment clauses in utility ratemaking in the United States. I explain that FACs are an important element in maintaining a vibrant and financially secure electric utility system that provides efficient, safe, adequate and reliable service—the benefits of which flow to customers over time. Finally, I address the compliance of HECO's current power cost recovery mechanism, the Energy Cost Adjustment Clause ("ECAC"), with recent legislation.[1]

Q. What are your conclusions?

A. I conclude the following:

- FACs are a standard and longstanding part of US utility ratemaking.
- HECO's ECAC is a well-designed FAC and benefits HECO and its ratepayers.
- HECO's ECAC complies with the statutory requirements of Act 162.

Q. How is your testimony organized?

A. In **Section II**, I discuss the historical context of and the economic and ratemaking rationale behind FACs and provide a brief description of the current status of power cost recovery in the United States, focusing mainly on traditionally-regulated (as opposed to restructured) states. In **Section III**, I evaluate HECO's ECAC in terms of the five specific requirements established by Act 162. **Section IV** concludes with a discussion of power cost "risk sharing" mechanisms.

SECTION II: BACKGROUND ON FUEL ADJUSTMENT MECHANISMS

A. Three Reasons for Fuel Adjustment Mechanisms

Q. What accounts for the common use of FACs?

[1] A Bill for an Act Relating to Energy, S.B. No. 3185, S.D. 2, H.D. 2, C.D. 1, Act No. 162, Approved by the Governor of Hawaii on June 2, 2006 (Herein after, "Act 162") amended Section 269-16 of the Hawaii Revised Statutes to include a subsection (g) that outlines requirements for the design of "any automatic fuel rate adjustment clause," of which the ECAC is one.

A. FAC mechanisms (and other cost-adjustment mechanisms) give utilities a reasonable opportunity to recover their legitimate costs of procuring electricity on behalf of customers. By providing timely cost recovery for power costs, the amount of time between rate cases—called "regulatory lag"[2]—can increase. The three classic reasons for FAC include:

1) The purchased item (most commonly fuel) is outside the control of the buying utility.
2) The item is a significant or large component of the utility's total operating costs.
3) The cost changes with respect to that item can be volatile and unpredictable.[3]

It is not necessary that individual cost items be large, volatile and unpredictable to qualify for FAC treatment. An effective FAC covers all purchased energy costs, including renewable sources, on an equal footing .

Q. Please explain the first reason to support an FAC.

A. Utilities procure fuel from markets and would normally not have the ability to control the price set in those markets. The 1991 NRRI Report notes that "[u]nless a utility is vertically integrated so that it owns the fuel source (whether it is the coal mine, gas well, or others), it is unlikely that the utility can exert much control over the cost of the fuel."[4] Moreover, the utility does not normally have the ability to control its customers' demand. It must procure the fuel and purchased power that are needed to meet customer demand as part of its obligation to serve.

[2] Between rate cases, utility managements have an incentive to control costs, seek new efficiencies, and avoid wasteful or unnecessary expenses. The longer they anticipate that period will be, the stronger the incentive. The reason is simple: until the next rate case is decided they get to keep any additional earnings generated.

[3] Robert Burns, Mark Eifert and Peter Nagler. "Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets," *National Regulatory Research Institute*, November 1991, p. 9. (Hereinafter referred to as the "NRRI Report.")

[4] NRRI Report, p. 4.

The utility, of course, has an obligation to procure its fuel and purchased power from the energy markets in a prudent manner. The NRRI Report notes that the utility is not "excused from hard-nosed, tough bargaining" and goes on to explain that state public utility commissions often hold utilities to a standard of prudent care in negotiating fuel contracts before allowing the cost to flow through a fuel adjustment or purchased gas adjustment clause.

Given prudent management, if certain costs (called "exogenous costs") are not within the control of the utility, the pursuit of economic efficiency calls for no penalty or gain to be borne by the utility as a result of changing market conditions. Exogenous cost changes represent any change in the cost of the firm—up or down—that is beyond the control of the firm. In a competitive industry, if these costs were required to provide a service, cost changes would alter the long run marginal and average cost curves of the industry and would directly affect the market price prevailing in the industry. Because exogenous costs are not under the control of the firm, passing such cost changes through to customers automatically cannot affect the incentive of the firm to behave efficiently or the market price standard to which regulated policies aspire. The pass-through of exogenous costs permits the regulated firm's prices to reflect market conditions (for the prices of its inputs) in just the way that input cost changes affect prices in unregulated, competitive markets, while providing a market price signal to customers.

Q. Please explain the second reason to support an FAC.

A. Fuel and purchased power costs continue to be a significant component of a utility's total operating costs. For all major investor-owned utilities ("IOUs") in the US, the average proportion of fuel and net purchased power relative to total operating expenses ranged from 35.8 to 54.3 percent during the 1992 to 2005 period.[5] Total fuel and net purchased power averaged 40.2 percent for the 1992-2005 period, as shown in **Figure 1**. The continued high proportion of fuel and purchased power costs relative to total operating costs shows that there is a continuing role for FACs as a tool for timely recovery of fuel and purchased power costs. HECO's fuel and purchased power expenditures represented about 66.8 percent of expenses in 2005, up from 64.1 percent in 2004 and 62.0 percent in 2003.[6]

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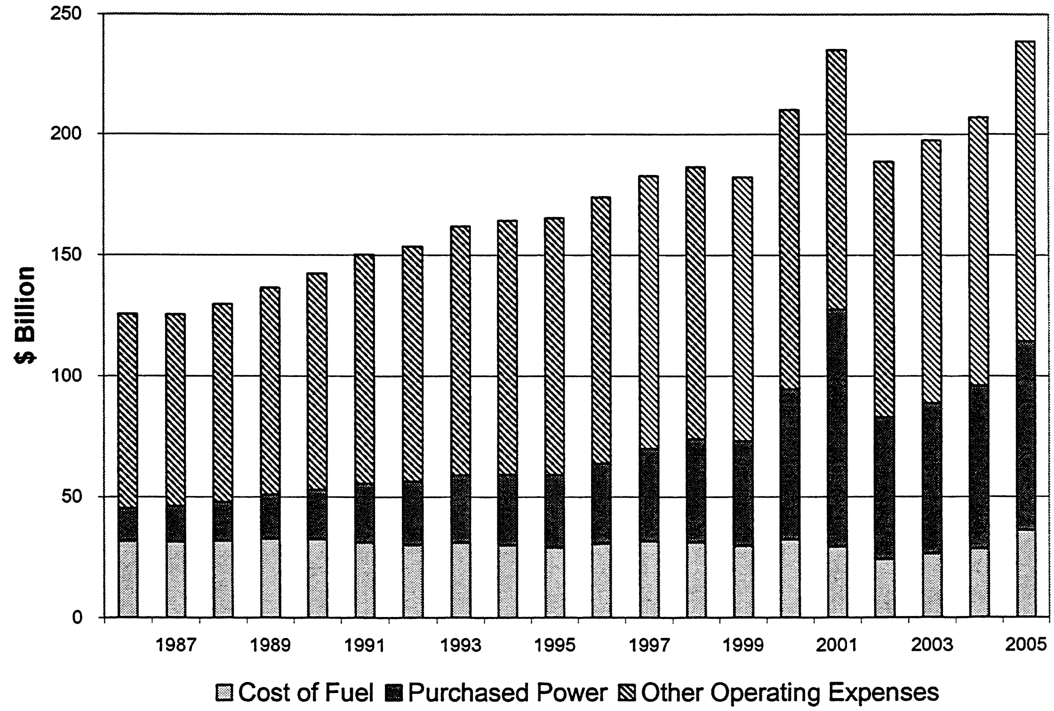
[5] Energy Information Administration, Electric Power Annual 2003, p. 49, Table 8.1 Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 1992 through 2003, December 2004. *See*: http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf (Accessed on December 18, 2006).

[6] Hawaiian Electric SEC Form 10-K for the period ending December 31, 2005, p. 62.

Figure 1. Fuel and Net Purchased Power Costs and Other Operating Expenses for U.S. Investor Owned Utilities, 1986-2005 [7]



Q. Please explain the third reason to support an FAC.

A. Changes in fuel and purchased power costs can be volatile and unpredictable. Although HECO is isolated from the wholesale electricity and natural gas markets, its primary source of fuel and purchased power expenses are dependent upon the market price for oil, which constitutes about 79.3 percent of HECO's fuel mix.[8]

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[7] Energy Information Agency. *Electric Power Annual, Vol. II.* "Revenue and Expense Statistics for Selected Investor-Owned Electric Utilities": Table 8.1 (1992-2005), Table 11 (1990-1994), Table 34 (1986-1990).

[8] HECO website, About Our Fuel Mix, Available at: http://www.heco.com/portal/site/heco/menuitem.508576f78baa14340b4c0610c510b1ca/?vgnextoid=047a5e658e0fc010VgnVCM1000008119fea9RCRD&vgnextchannel=deeaf2b154da9010VgnVCM10000053011bacRCRD&vgnextfmt=default&vgnextrefresh=1&level=0&ct=article (Accessed December 7, 2006).

State commissions continue to cite the unpredictable nature of fuel and purchased power costs that, if unaccounted for, would leave the utility to bear the burden and financial risk of volatility. For example, the Louisiana Public Service Commission states that the "Fuel Adjustment Clause mechanism…has been established due to the materiality and historical and potential volatility of these costs."[9]

A utility must serve its customers under all weather and energy market conditions and therefore must purchase fuel and power to satisfy demand during peak periods during the year (*i.e.*, unusually cold winter days or warm summer days). Recent history has shown that events outside a utility's control can increase the volatility of oil, purchased power and other fuel prices.

B. Current Status of FACs in U.S.

Q. What is the current status of power cost recovery in the United States?

A. FACs are prevalent throughout the U.S. Of the 32 traditionally regulated states, only Utah and Vermont lack FACs.[10] Many states have instituted state-wide FAC mechanisms available to all electric (or gas) utilities. Some states have dealt with each utility on a case-by-case basis, which has led to inconsistencies across utilities within these states regarding power cost adjustments. **Figure 2** summarizes the current status of FACs.

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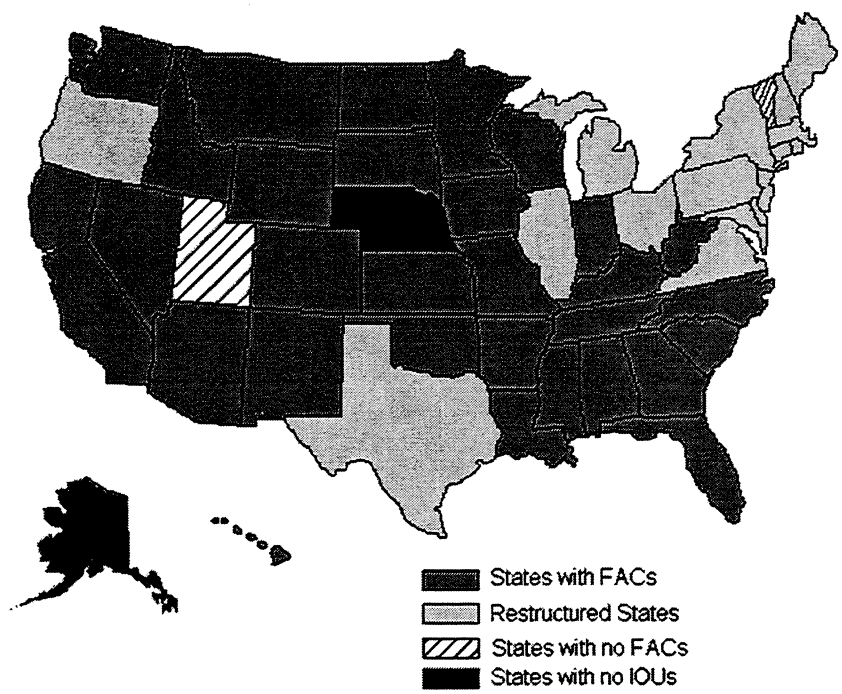
9 Before the Louisiana Public Service Commission, "Development of standards governing the treatment and allocation of fuel costs by electric utility companies," General Order, Docket No. U-21497, October 1, 1997.

10 Most electric restructuring states have implemented some mechanism to pass through Provider of Last Resort (POLR) or Standard Offer Service (SOS) charges.

Figure 2. Current Status of Fuel Cost Adjustments in the U.S.



C. Historical Context

Q. How did FACs become a common regulatory practice in the U.S.?

A. FACs were initially established as a response to specific shocks, such as high coal prices following WWI and inflation following WWII.[11] By the late 1950s, FACs were commonplace, albeit infrequently used for actual rate changes due to relatively stable input costs. The OPEC oil crisis of 1972-73, however, put FACs back in the spotlight. Many state regulators began pushing for uniformity across their states.

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[11] Michael Schmidt provides a useful summary of the early history of FACs. See: Michael Schmidt, *Automatic Adjustment Clauses: Theory and Application* (East Lansing, MI: MSU, 1980), pp. 10-11

By 1990, 40 jurisdictions had long-standing FACs in place.[12] In Hawaii, an oil cost recovery charge has been in place since at least the 1920s.[13]

D. Description of HECO's ECAC

Q. Have you examined HECO's current FAC mechanism, the ECAC?

A. Yes.

Q. What did you find?

A. The ECAC includes both fuel and purchased power costs. It computes monthly weighted average of the various fuel and purchased power costs based on fuel mix, which is then converted to a rate for customers based on the estimated MWh sales for the month. The ECAC uses an efficiency factor (measured in MBtu/kWh) to calculate the conversion between the MBtu of fuel purchased and the amount of kWhs generated. The ECAC contains a quarterly reconciliation for the previous quarter's actual experienced fuel and purchased power expenses on a per kWh basis relative to the forecasted amounts. This reconciliation ensures the timely recovery of fuel and purchased power costs for HECO.

Q. How would you compare HECO's ECAC to the power cost recovery practices of the rest of the United States?

A. The ECAC comparables well to the FACs that are used in traditionally-regulated jurisdictions in the U.S. Nearly all traditionally regulated and most restructured states have some similar mechanism for power cost recovery with complete fuel cost recovery. In **Section IV**, I will discuss the few cases where the FAC mechanism

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[12] NRRI Report, p. 9.

[13] The Hawaii Electric Co.'s tariffs for 1928 show that "[t]he rates set forth in this schedule are based on the cost to the Company of fuel oils delivered in the Company's tanks at Two Dollars ($2.00) per barrel. For each advance of one whole cent per barrel in excess of $2.00 per barrel of fuel oil, an additional charge of $0.00004 per kWh will be made for all current supplied in excess of 5000 kWh per month." A similar reduction occurred if oil prices dropped. *See*: Tariffs for The Hawaii Electric Co, Ltd. Revised Sheet No. 53, Issued July 1, 1928, Schedule P-1.

does not fully pass through fuel and purchased power costs. Like the ECAC, most (about 22) of the 30 traditionally regulated states with fuel clauses have some form of true-up mechanism to reconcile actual and forecasted cost recovery. Also, about 13 of those same states have rate adjustments on a quarterly or more frequent basis.

SECTION IV: ECAC'S COMPLIANCE WITH ACT 162

Q. Please describe the new requirements for Automatic Fuel Rate Adjustment Clauses outlined in Act 162.

A. Act 162 incorporates five requirements for the design of any public utility automatic rate adjustment. Act 162 requires that any automatic rate adjustment be designed to:

1. Fairly share the risk of fuel cost changes between the public utility and its customers;
2. Provide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy;
3. Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as fuel hedging contracts;
4. Preserve, to the extent reasonably possible, the public utility's financial integrity;
5. Minimize, to the extent possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs.[14]

I now consider the ECAC's compliance with each of these requirements.

A. Fair Risk Sharing of Fuel Cost Changes

Q. What is the "risk of fuel cost changes?"

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[14] Section 269-16(g) of the Hawaii Revised Statutes as revised by Act 162, pp. 17-18.

A. The risk of fuel cost changes comprises two things:

- Changes in the *price* of fuel as a single productive input; and,
- Changes in the *cost* to deliver and produce electricity from HECO's fuel inputs. This reflects any changes in the technical ability of the utility to turn purchased fuel into electricity, which may require HECO to purchase a greater *quantity* of fuel, and thus increase the overall level of fuel costs, in order to produce the same amount of electricity.

Q. How should the risk of changes in the *price* of fuel as a productive input be "fairly shared?"

A. Fair risk sharing occurs when the utility has the means to control a cost and it has a corresponding incentive to do so (*i.e.*, it shares the risk associated with that cost). It is not economically efficient to impose risk of cost recovery on the utility when the utility is not able to control the cost. This distinction is critical because the *price* of fuel is, realistically, beyond the control of the utility. HECO acts as a price taker in the world-wide market for fuel (oil) and the design of the ECAC and the recovery of fuel and purchased power costs should recognize this fact.

Under the ECAC, exogenous changes in fuel *input* costs are passed fully onto consumers. In fuel markets (as in other markets where HECO is a price taker – service vehicles, for example), it is straightforward to demonstrate prudent purchasing. There is a well-defined market price and a well-defined need to buy from this market (*i.e.*, ratepayers' demand for electricity). In a price-taking market, imposing price change risks on the utility would lead to no efficiency gains resulting from management incentives to minimize costs. This supports the utility's ability to maintain its financial viability, and would increase regulatory lag—the time between rate cases—for costs that *are* within the utility's control, which would enhance the utility's incentive to control its base rate costs.

Q. Please describe the risk of changes in the *cost* to deliver and produce electricity from HECO's fuel inputs.

A. The ECAC, with its "heat rate" efficiency factor, provides a partial pass-through of fuel costs. It shares the risks and/or benefits of increased plant operating efficiency by tying HECO's ability to recover its fuel costs (and thus its financial performance) to its power plant performance over which it has some managerial control, while also allowing HECO to pass through the exogenous changes in the price of an input over which it has no control, the price of fuel and purchased power.

HECO has considerable control over the operation of its plants—limited by engineering realities—and therefore it is reasonable, as the Commission already does, to provide HECO with an incentive to improve its operating efficiency to manage or lower its fuel costs.

The general role that management plays in an investor-owned utility should be recognized. Efficient and prudent management strives to minimize the amount of inputs while maximizing the production of the final product – safe, adequate and reliable service at the lowest reasonable cost. Viewed from this perspective, management *should* have an incentive to manage efficiently the selection of inputs (of which fuel and purchased power are two of many)—and HECO does have this incentive.

This heat rate efficiency factor properly assigns the risk of changes in the cost to deliver and produce electricity from HECO's fuel inputs to HECO's management, while allowing changes in the price of fuel to be passed through to ratepayers.

Q. Are plant performance and heat rate targets used in other jurisdictions?

A. Yes. State commissions in Florida, Louisiana, and North Carolina are examples of jurisdictions that have established specific incentives for power plant performance.[15] A "Generating Performance Incentive Factor" is included in fuel and purchased power recovery clauses in Florida, which rewards the utility (up to a 25 basis point spread) when generation assets achieve certain performance benchmarks in availability and heat rate.[16] In North Carolina, the allowed level of fuel-cost recovery is linked to achieved nuclear capacity factors.[17] These are reasonable approaches, which provide the utility an incentive to improve plant performance, something that it does have considerable control over.

Q. What are the potential costs associated with improperly assigning power cost recovery risk to the utility?

A. Doing so could harm the utility's financial health, its credit rating and its ability to raise capital from the financial markets. Accordingly, if a utility only partially recovers its power costs through its FAC, investors will require a higher return on their capital to reflect the riskier investment.[18] While a partial pass-through of power costs may initially reduce the level of rates when unexpected fuel price increases occur, it will ultimately lead to higher costs to consumers. I discuss the regulatory history of power cost risk sharing mechanisms in **Section IV**.

B. Utility Incentives for Fuel Costs and Renewable Energy

Q. What is the second condition required by Act 162?

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[15] Regulatory Research Associates, Alternative Ratemaking / Incentive Ratemaking, February 15, 2005.

[16] *Id.*

[17] *Id.*

[18] A utility's cost of equity is set based on a comparable group. Nearly all utilities have cost-recovery mechanisms in place.

A. Act 162 requires that automatic rate adjustment mechanisms be designed to "[p]rovide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy."

This condition is closely tied to the previous one. HECO's targeted efficiency factor promotes productive fuel use decisions and gives HECO an incentive to reasonably manage or lower its fuel costs.

If HECO achieves more efficient plant performance than the level of the efficiency factor (currently set at 0.11170 Mbtu/kWh), then sees a HECO reward. If it fails to meet this target for some reason, then it would not be able to recover the additional purchased fuel expenditures required to produce the kWhs.

Q. Should all purchases of fuel and electricity (renewable and non-renewable) be on an equal footing?

A. Yes. The ECAC should cover all purchased energy costs, including renewable sources, on an equal footing within the cost recovery mechanism. Renewable energy resources can be part of a utility's power procurement to the extent that they are cost-efficient, reliable and represent a diverse source of generation relative to the traditional non-renewable resources. Like many utilities, HECO creates and follows an Integrated Resource Plan ("IRP"), which determines the extent of renewables used in HECO's fuel mix. The IRP process balances cost-minimization with resource diversity and other concerns. Like purchasing fuel oil from the oil markets, purchasing energy from renewables is not without risks. To ensure the efficient use of renewable resources, the ECAC would cover all purchased energy costs, including renewable sources, on an equal footing. Currently, the ECAC is adjusted each month for changes in the energy mix of the sources of fuel and purchased power. Under an equal footing structure, there is no disincentive from a cost recovery standpoint to purchase renewable energy. The encouragement of renewable energy above and beyond a treatment paralleling non-renewables (*i.e.*, direct subsidization) is a matter of public policy and should not be confused with energy cost recovery.[19]

Q. Could a frequently updated and well designed FAC mechanism support renewable resource development?

A. Yes. The ECAC has positive financial implications and can improve a utility's credit ratings, thereby moderating the cost of capital borne by ratepayers. Because the utility serves as a counter-party for renewable energy companies, the credit standing of a utility frequently serves as an important determinant of renewable energy projects' ability to raise capital, and thus, improve reliability and resource diversity. Weakening the utility's credit rating through partial power cost recovery could harm renewable resources that rely on utility counter-party credit to support their investments.

Q. Act 162 is concerned specifically with the incentive structure facing utilities. Is this the only set of incentives a regulator should evaluate?

A. No. Just as it is proper in the pursuit of economic efficiency for utilities to have incentives to efficiently manage costs over which they have control, economic efficiency is also served if ratepayers have a cost-based price signal. Ratepayers will not choose to consume an efficient level of electricity if they are shielded from the true costs of producing electricity, and a timely FAC therefore has an important role to play in transmitting these price signals. When consumers are aware of, and can respond to, the cost effects of their energy consumption decisions, they may

[19] Purchased capacity costs of renewable resources is not recovered through the ECAC. A separate cost adjustment is used for these costs.

reduce their demand when the price outweighs the benefit of consuming the product. Braulio Baez, the Chairman of the Florida Public Service Commission states in a Consumer Bulletin concerning fuel price adjustments:

> The action of removing fuel costs from base rates had the effect of reducing fluctuations in base rates. Both the utilities and their customers now had a better incentive to respond to fuel price changes. Because non-fuel expenditures are more stable than fuel expenditures, utilities were not only less likely to seek base rate adjustments, but any rising costs also provided the utility with a greater incentive to use other, less expensive fuels to generate electricity. [20]

Q. What do you conclude regarding this condition?

A. I conclude that so long as the ECAC treats all sources of generation equally and allows the recovery of energy costs from all sources, it complies with this condition.

C. Management of Price Volatility

Q. What is the third requirement established in Act 162?

A. This requirement requires "the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as fuel hedging contracts."

Q. What are the potential impacts of hedging fuel costs?

A. There are no free lunches in risk management. As discussed in Mr. Meehan's testimony, hedging has real costs to the party that wishes to reduce its exposure to

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[20] Braulio L Baez, "Customer Bulletin," Florida Public Service Commission, April 2004.

price movements.[21] In some years, ratepayers may benefit from a price hedge as prices rise, but in times when prices do not rise or fall this will not be the case. In the long run, hedging programs can be expected to increase the overall level of costs associated with fuel and purchased power expenses. Accordingly, if there is a mandate for the utility to reduce ratepayers' exposure to the potential rise in fuel costs, these hedging costs should be passed onto ratepayers.

Q. Act 162 recognizes that there are alternatives "commercially available" to customers that can mitigate price risk for customers. How can a utility mitigate the risk of fuel cost changes?

A. There are two forms of hedges:

1. Physical hedges, such as long-term supply and purchased power contracts and maintaining fuel inventories. The costs of existing contracts are included in the current ECAC computations.
2. Financial hedges. Testimony presented by Mr. Meehan surveys the potential financial hedging instruments that are available to HECO and their potential impacts.[22] Generally, financial hedges either require payment to intermediaries in cash to bear risks or otherwise pay through giving up the prospect for lower future fuel prices. If utility ratepayers are willing to pay for the additional service of hedging their price risk, the ECAC would include these costs. Currently, the ECAC allows the recovery of the unhedged fuel costs, but is unclear regarding whether financial hedging costs would be recovered in the ECAC.

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[21] Testimony of Gene Meehan, Before the Hawaii Public Utility Commission, Docket No. 2006-0386, p. 4.

[22] *Id.*, p. 19.

Q. Are there alternatives available other than hedging price risk changes that can provide similar rate smoothing benefits to price risk hedging?

A. Yes. There are alternatives to price hedging, such as budget billing plans and fixed rate plans.

Q. What is budget billing?

A. Budget billing is an optional payment program that allows the customer to pay the same amount each month for electricity or natural gas usage throughout the entire year. The voluntary nature of these programs limits any negative consumer feedback and targets the program to the consumers that want it. A monthly bill based upon previous usage patterns is estimated for the upcoming year.[23] At the end of the year, there is a true-up between the amount paid by the ratepayer and the amount the ratepayer would have paid, given his actual usage, under a non-budget billing rate plan. Budget billing is typically offered to residential and small commercial customers as part of a plan to manage volatile changes in monthly energy costs. It should be noted that budget billing does nothing to mitigate rising electricity costs. Participants still pay the full amount for electricity, only the timing of payments over the course of the year is adjusted. Most states currently have a form of budget billing program available to residential customers.[24] The need for a budget billing plan in Hawaii may not be as large as most continental U.S. states due the relative lack of seasonality in demand.

Q. Please describe the other rate option, fixed rate billing.

A. Some states have allowed utilities to have a rate option called "fixed rate" or "flat bill" in which a customer pays a flat bill with no reconciliation, but with a risk

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[23] Some programs have more frequent adjustments (such as quarterly).

[24] In our survey, evidence of some form of budget billing was found in 47 U.S. states and the District of Columbia. Only Hawaii, Alaska and Rhode Island did not have a budget billing program.

premium. Fixed rate billing programs are generally available for larger commercial and industrial users who value (and are willing to pay for) insulation from unexpected price increases.

The risk premium is necessary because fixed rate billing does present risks and additional costs to the utility. If fuel and purchased power prices are higher than expected, fixed rate billing will under-collect. The opposite is also true. Therefore, customers electing a fixed rate billing option may force the utility to hedge against a position in the market for the underlying oil commodity. If a utility offering a fixed rate or flat bill program did not hedge against this fixed price obligation, they would be effectively speculating on the fuel markets. As discussed in the testimony of Mr. Meehan, there is an inability to hedge HECO's fuel price exposure fully.[25] Thus, any expected costs that may result from a fixed rate billing program would increase the flat bill rate over the regular tariff structure. The risk premium should be large enough to compensate the utility for any added risks and costs on average, but during periods of rising fuel prices, a large group of ratepayers taking out a fixed rate may affect a utility's liquidity and its financial health.

Fixed rate billing may provide benefits to larger customers similar to budget billing (rate stability) with the added benefit of insulation from input cost increases. Rates will, on average, be higher for the customers who select this option.

Q. What do you conclude regarding the ECAC's compliance with the third condition of Act 162?

A. If there is a demand from customers and/or a mandate from the Commission acting on behalf of ratepayers, then recovery of the hedging and risk premium costs

[25] Testimony of Gene Meehan, Before the Hawaii Public Utility Commission, Docket No.2006-0386, pp. 4-5.

associated with physical and financial hedges should be included in the ECAC. However, there are other alternatives available, such as budget billing and fixed rate billing, that may provide the benefits sought through hedging programs (rate stability), and which would not require pursuing these potentially costly options.

D. Preservation of Utility Financial Integrity

Q. What is the fourth requirement of Act 162?

A. The fourth requirement is to "[p]reserve, to the extent reasonably possible, the public utility's financial integrity."

Q. How does a FAC generally, and the ECAC specifically, preserve the financial integrity of a utility and HECO in particular?

A. For modern utilities that operate in a world of volatile fuel prices, an FAC is critical to:

- Reduce the volatility of utility earnings. Companies exhibiting large earnings volatility are typically those with most difficulty in tracking input costs.
- Provide the utility with a reasonable opportunity to recover its prudently-incurred costs in rates.
- Lower the risks to capital invested in a utility and thus lower the utility's cost of capital (and ultimately, rates) as well as help maintain the utility's credit rating.[26] Volatile wholesale power and oil and gas commodity markets have led the rating agencies to more closely scrutinize cost-recovery mechanisms. Credit rating agencies, for example, recognize the need for robust and frequently updated FAC mechanisms. **Exhibit HECO – 2101** presents a selection of statements from the three major credit rating agencies detailing the critical role of power cost recovery in their credit rating evaluation process.

[26] Again, most of any particular utility's peers also have an FAC and therefore a lack of an FAC would increase a utility's risk relative to its peers.

- Maintain HECO's ability to raise capital. Because oil, and other fuel expenses, are a large portion of HECO's operational costs (see **Figure 1**), the ECAC is necessary because it allows HECO to raise capital at a reasonable cost in good markets and bad.

Utility regulators have long recognized the crucial role that cost-recovery mechanisms play in allowing the utility an opportunity to recover its costs. FACs permit a utility to recover its costs and assure the capital markets that the company can meet its obligations to shareholders and bondholders. Colorado provides an example of the Commission balancing the concerns of the utility and its customers. The Colorado PUC explained their long-term use of FAC mechanisms by stating that they established their FAC in order to permit rapid recovery of increased costs over which the utility has no control. The PUC recognized that, in the circumstances which existed at the time, unless increased fuel costs were passed through to customers expeditiously, the utility would undergo a serious erosion of earnings jeopardizing the utility's ability to provide service.[27]

When approving the Arizona Public Service Company's ("APS") proposed Power Supply Adjustor, the Arizona Corporation Commission stated "we agree that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating" and that "an adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity in a rate case and result in lower rates."[28]

[27] Before the Public Utilities Commission of the State of Colorado, "In the Investigation of Electric Cost Adjustment Clauses For Regulated Electric Utilities," Docket No. 93I-702E, Decision No. C95-248, February 6, 1995.

[28] Before the Arizona Corporation Commission, "In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and For Approval of Purchases Power Contract," Docket No. E-01345A-03-0437, Decision No. 67744, pp. 16-17.

Q. What do you conclude regarding the ECAC's role in preserving HECO's financial integrity?

A. Continuation of the ECAC would allow HECO to more readily raise capital in the future, which will improve its ability to meet future infrastructure needs and preserve the level of service demanded by its ratepayers and the Commission. HECO recognizes this fact when it states in its most recent 10-K that:

> Risks, uncertainties and other important factors that could cause actual results to differ materially from those in forward-looking statements and from historical results include, but are not limited to…fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses.[29]

E. Minimize Regulatory Costs

Q. What is the fifth and final requirement established by Act 162?

A. The fifth requirement is to "[m]inimize, to the extent possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs."

Q. How does the ECAC help minimize regulatory costs and meet this condition?

A. In general, FACs are designed to reduce regulatory costs by separating the volatile fuel costs from the rate base. A prime motivation for FACs is a reduction in base rate cases. The reduction of frequent base rate cases does not reduce the Commission's oversight of HECO's fuel and purchased power expenditures.

[29] Hawaiian Electric, SEC Form 10-K for the period ending December 31, 2005, p. 10.

Electricity FACs can allow for recovery of narrowly-defined categories of fossil fuel costs, nuclear fuel costs, purchased power, fuel transportation costs, and hedging costs, among others. Calculations supporting the ECAC are submitted to the Commission for review on a monthly basis.

Q. Is there any way that the ECAC could be updated to further minimize regulatory costs and the need for frequent base rate cases?

A. To further minimize regulatory costs, regulators can see that any other cost category that meets the three criteria for an automatic rate adjustment discussed in the background section receive parallel treatment to those costs already included in the ECAC. Cost categories to consider tracking separately or including in the ECAC include the following:

- All fuel and purchased power costs,
- Purchased capacity (especially considering the discussion of renewables),
- Hedging costs,
- Environmental compliance costs, and
- Any other costs specific to the jurisdiction that meet the three criteria I discussed earlier.

The breadth of adjustment clauses is not limited to fuel and purchased power expenses. Rather, the ECAC or a similar adjustment mechanism can be implemented efficiently for other costs that are large, volatile and beyond the control of the utility. Also, adjustment and cost tracking mechanisms may be implemented to allow for the parallel treatment of similar costs categories. For example, demand-side management ("DSM") costs provide a substitute for pursuing supply-side resources. If supply-side resources are recovered under a FAC, DSM costs could be treated symmetrically, which would treat supply- and demand-side energy costs on an equal footing.

Q. How would implementing a fuel price hedging program affect the frequency of HECO's base rate cases?

A. Currently, the ECAC does not recover hedging costs. If HECO implemented a hedging program without the ability to recover hedging costs through the ECAC or a comparable rate adjustment mechanism, there would be a potential increase in the need to file expensive base rate cases. Hedging costs, because they are directly tied to fuel and purchased power costs, fit the three criteria established in **Section II** for an "automatic" rate adjustment. Costs that are large, volatile and generally beyond the utility's control can dramatically impact a utility's financial performance and may prevent a utility from earning its allowed ROE.

Section IV: Power Cost Risk Sharing Mechanisms

Q. What other ways have Commissions decided to share the risk of power cost changes?

A. Some states have adopted partial pass-through mechanisms. Note that these are some times referred to as "risk sharing" mechanisms, but that characterization is incorrect given that a utility is a price taker, and would not be able to control the price of fuel and purchased power acquired from the market. **Table 1** provides a brief overview of these mechanisms.

Table 1. State Experience with Partial Pass-Through Mechanisms

State (Utility)	Mechanism
Arizona (Arizona Public Service)	90 percent of any costs or savings relative to the base level would be allocated to customers and 10 percent is allocated to the company.
Colorado (Public Service Co. of Colorado)	Graduated sharing mechanism relative to a base level: The first $15 million is allocated 50/50. The next $15 million is allocated 75/25. Any changes above $30 million are to be recovered from or flowed back to ratepayers. The maximum profit or loss that PSCO will absorb is $11.25 million in any one year.
Idaho (Idaho Power)	The power cost adjustment is 90 percent of the difference between the Projected Power Cost and the Base Power Cost plus the True-ups.
Washington (Puget Sound)	Graduated sharing mechanism: PSE will absorb the first $20 million relative to the baseline, 50 percent of the next $20 million, 10 percent of the next $80 million, and 5 percent of any amount that exceeds $120 million. The WUTC also implemented a "power-cost-only rate case," so PSE can update its baseline rate to reflect power costs.
Washington (Avista)	Originally, the first $9 million is absorbed by the company (an $18 million deadband) and 90 percent of the energy cost differences exceeding the initial $9 million to be deferred for a later rebate or surcharge to customers. The parameters were modified in July 2006 to a $4 million deadband, a 50/50 sharing of energy cost differences between $4 million and $10 million and a 90/10 sharing of power costs in excess of $10 million.

Q. What do you conclude in your analysis of the above partial pass-through mechanisms?

A. These jurisdictions blur the distinction between risk sharing for productive purposes and risk sharing in the price-taking purchase of inputs. In other words, some jurisdictions impose risk sharing on the *price* of fuel and purchased power. However, these cases are idiosyncratic and have generally been a phase in a broad movement toward less risk imposed on the utilities involved in fuel and power purchases. In all cases where a partial pass-through mechanism is used, the fuel and purchased power costs that are not allowed recovery in the FAC are apportioned to the utility for the FAC mechanism only—the companies can file rate cases to recover these increased costs (although with the expense and uncertainty of rate cases).

Generally, the implementation of risk sharing mechanisms has represented a movement toward the full pass through of costs. In Arizona, FACs were suspended in 1989, but APS established a new one in a settlement to the 2003 rate case. Thus, APS went from zero percent pass-through to 90 percent pass-through of fuel and purchased power costs. In Colorado, Public Service Company of Colorado ("PSCO") has other adjustment clauses for DSM costs, air quality improvement costs and purchased capacity that may compensate the utility for the increased fuel and purchased power risks. In its current rate case, PSCO extended its use of its FAC, but was also granted two associated incentive mechanisms: 1) if PSCO achieves coal production greater than a benchmark target, the associated savings would be shared 80/20 with customers, and 2) PSCO would share 80 percent of savings (above a deadband) related to the purchase of economic short term energy.[30] In Idaho, Idaho Power absorbed all fuel cost changes prior to 1993, 40 percent from 1993 to 1995, and only 10 percent thereafter. Still, major fuel and purchased power cost deferrals (for later collection after contentious base rate proceedings) occurred during the 2000-01 Western Power Crisis where electricity prices spiked to over $1,000 per MWh. The story in Washington follows similar lines. Neither utility had an FAC and power costs were recoverable through base rate cases. Recent variations in hydroelectric generation supply (due to a seven year drought) increased the size of deferrals and threatened the utilities' finances. Avista filed a petition on January 30, 2006, proposing to eliminate the $18 million deadband of their Energy Recovery Mechanism ("ERM"). In a settlement, Avista's deadband was narrowed to $8 million ($4 million above and below the base level) with a 50/50 sharing of power costs between $4 million and $10 million and a 90/10 sharing of power costs

[30] Regulatory Research Associates, Focus Note: Public Service of Colorado, November 22, 2006.

starting at $10 million above or below the base level. The settlement also called on Avista to examine the cost of capital impact of the ERM, as well as the company's hedging strategy for fuel and wholesale power purchases.[31] This represents another movement towards full pass through of power costs.

The fuel mix and thus exposure (and risk) to oil market price risk of the above utilities are also dramatically different than HECO, which relies heavily upon oil for its generation needs. **Table 2** shows that oil plays an insignificant role in these utilities' generation mix and its fuel and purchased power costs. Their large hydro, nuclear and coal resources mitigate much of their exposure to the volatile oil and natural gas markets.

[31] Regulatory Research Associates, Focus Note: Avista, July 21, 2006.

Table 2. Fuel Mix for Utilities / States with Partial Pass-Through Mechanisms

Fuel Type / Source	HECO[1]	APS[2]	PSCO[3]	Idaho[4]	Washington[5]
Hydro	0.5%	0.0%	0.0%	46.0%	66.0%
Coal	14.3%	39.3%	45.0%	47.0%	17.7%
Nuclear	0.0%	22.6%	10.0%	0.0%	5.3%
Gas	0.0%	9.1%	38.0%	6.0%	9.5%
Oil	79.3%	9.1%	0.0%	0.0%	0.1%
renewables / other	5.9%	19.7%	7.0%	1.0%	1.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Sources:

1 HECO website, About Our Fuel Mix, http://www.heco.com/portal/site/heco/menuitem.508576f78baa14340b4c0610c510b1ca/?vgnextoid=047a5e658e0fc010VgnVCM1000008119fea9RCRD&vgnextchannel=deeaf2b154da9010VgnVCM10000053011bacRCRD&vgnextfmt=default&vgnextrefresh=1&level=0&ct=article (Accessed on December 12, 2006).

2 Arizona Public Service, Generation Fuel Mix and Emission Characteristics, http://www.aps.com/_files/services/BusRates/disclosure.pdf (Accessed on December 18, 2006). Note that APS does not distinguish between gas and oil. They report that gas/oil comprises 18.2% of generation, for illustrative purposes this was split 50/50.

3 Xcel Energy Fuel Supply Sources, http://library.corporate-ir.net/library/89/894/89458/items/223379/12_6XcelUtilityWeekSECwAppendix12062006.pdf (Accessed on December 18, 2006)

4 Generation Options for Idaho's Energy Plan, presentation to the Subcommittee on Generation Resources, August 10, 2006, http://www.legislature.idaho.gov/sessioninfo/2006/Interim/energy_e3_0810.ppt#561,31,2005 Idaho Electricity Fuel Mix (Acessed on December 12, 2006).

5 State of Wahsington, Department of Community, Trade and Economic Development, Fuel Mix Disclosure, http://www.cted.wa.gov/site/539/default.aspx (Accessed on December 12, 2006).

Q. After examining these partial pass-through mechanisms and the ECAC's efficiency factor, what can you conclude regarding the ECAC's compliance with the first provision of Act 162?

A. A fuel efficiency factor is an incentive that is *targeted* at a utility's production decisions and isolates the utility's production performance. Partial pass-through mechanisms are rare and have been adopted for utilities with no existing FAC in place and should not be considered as a viable option for the sharing of fuel and purchased power costs in Hawaii.

Q. What do you conclude regarding the use of FACs?

A. Fuel prices constitute a large and volatile cost for price-taking utilities. A well-established, frequently-updated FAC is essential to maintain a utility's credit and operational viability and thereby meet the requirements of customers.

Q. Does this conclude your testimony?

A. Yes, it does.

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Dr. Makholm concentrates on the issues surrounding the privatization, regulation and deregulation of energy and transportation industries. These issues include the broad categories of efficient pricing, market definition and the components of reasonable regulatory practices. Specific pricing issues include tariff design, incentive ratemaking, and the unbundling of prices and services. Issues of market definition include assessments of mergers, including the identification and measurement of market power. Issues of reasonable regulatory practices include the creation of credible and sustainable accounting rules for ratemaking as well as the establishment of administrative procedures for regulatory rulemaking and adjudication. On such issues among others, Dr. Makholm has prepared expert testimony, reports and statements, and has appeared as an expert witness in many state, federal and U.S. district court proceedings as well as before regulatory bodies and Parliamentary panels abroad.

Dr. Makholm's clients in the United States include privately held utility corporations, public corporations and government agencies. Focusing mainly in the areas of gas and electric utilities, he has represented dozens of gas distribution utilities, as well as both intrastate and interstate gas pipeline companies and gas producers. Dr. Makholm has also worked with many leading law firms engaged in natural gas and electricity issues.

Internationally, Dr. Makholm has directed an extensive number of projects in the utility and transportation businesses in 20 countries on six continents. These projects have involved work for investor-owned and regulated business as well as for governments and the World Bank. These projects have included advance pricing and regulatory work prior to major gas, railroad and toll highway privatizations (Poland, Argentina, Bolivia, Mexico, Chile and Australia), gas industry restructuring and/or pricing studies (Canada, China, Spain, Morocco, Mexico and the United Kingdom), utility mergers and market power analyses (New Zealand), gas development and and/or contract and financing studies (Tanzania, Egypt, Israel and Peru), regulatory studies (Chile, Argentina), and oil pipeline transport financing and regulation (Russia). As part of this work, Dr. Makholm has prepared reports, drafted regulations and conducted training sessions for many government, industry and regulatory personnel.

Dr. Makholm has published a number of articles in Public Utilities Fortnightly, Natural Gas and The Electricity Journal—many involving emerging issues of wholesale and retail competition in gas and electricity, including the issues of unbundled and competitive transport, secondary markets and stranded costs. He is a frequent speaker in the U.S. and abroad at conferences and seminars addressing market, pricing and regulatory issues for the energy and transportation sectors.

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RECENT TESTIMONY (SINCE 1994)

Before the Public Utilities Commission of Nevada, Rebuttal Testimony of Jeff D. Makholm on behalf of Sierra Pacific Power Company, Docket No. 06-05016. October 2, 2006. Subject: Prudence of gas purchase costs.

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"Evaluating the Threat of Municipalization, The Economics of Uncertainty with Municipalization Case Studies," with J. James Tasillo, Jr., NERA Working Paper, May 1988.

"Pareto Optimality Through Non-Collusive Bilateral Monopoly With Cost-Of-Service Regulation," with C. J. Cicchetti, NERA Working Paper, April 1988.

"The FERC Discounted Cash Flow: A Compromise in the Wrong Direction," with C. J. Cicchetti, *Public Utilities Fortnightly*, July 9, 1987. pp. 11-15.

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A Critique of CEPA's Report on "Productivity Improvements in Distribution Network Operators:" A report for EDF Energy (with Graham Shuttleworth). December 16, 2003.

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"Natural Gas Pipeline Access Regulation". Report prepared for BHP Petroleum Pty Ltd., May 31, 2001.

"Manual de Procedimientos para el Sistema Uniforme de Cuentas Regulatorias Eléctricas (SUCRE) de México" (April 2000). The report includes an explanation of each of the accounts needed for regulation, recording procedures and the structure the information should take when reporting to the regulator.

"Investigation into Petronets' Liquid Fuels Pipeline Tariffs: Final Report" (March 9th, 2000). This report presents NERA opinions in the quasi-arbitration of the tariffs disputes in the oil industry in South Africa for their liquids pipelines.

"Seeking Genuine Gas Competition in NSW":, prepared for BHP Petroleum Pty. Ltd., February 18, 2000.

"Análisis y Revisión del Recurso de Revocatoria Interpuesto por la Compañía Boliviana de Energía S.A. (COBEE) a la Resolución SSDE Nº 92/99 de la Superintendencia de Electricidad" (September 6, 1999). This report represents NERA's opinion on COBEE's appeal in the electricity tariff review process in Bolivia (report in spanish).

"Gas Sector Regulation Consultancy Services" report prepared for the Vietnam Oil and Gas Corporation, August 10, 1999.

"Natural Gas Demand Estimation for Guatemala, Honduras and El Salvador" (July 19th, 1999). This report done for an international consortium of companies presents calculations of prices and volumes of natural gas demand for three Central American countries if a pipeline is built from Mexico.

"Comments on East Australian Pipeline Limited Access Arrangements: (July 15, 1999). Report prepared on behalf of Incitec Ltd.

"Supplementary Submission to IPART on AGLGN's Proposed Access Arrangements" on behalf of Incitec Limited (April 27th, 1999). This submission discusses reload practices, customer contributions, operating expenses and recalculates charges for a user of the distribution network in New South Wales, Australia.

"Supplementary Submission to IPART on AGLGN's Proposed Costs and Tariffs" on behalf of BHP (April 15th, 1999). This submission explains how NERA recalculated charges for AGLGN in New South Wales, Australia.

"Initial Comments on AGLGN's Revised Access Arrangement Information" on behalf of BHP (March 20th, 1999). This submission presents NERA's comment to AGLGN submission to IPART in New South Wales, Australia.

RECENT INTERNATIONAL REPORTS (CONT.)

"International Restructuring Experience" (February 12th, 1999). This paper surveys a number of countries whose experience of restructuring and competition in the electricity sector is directly relevant to the proposed changes in Mexico – Argentina, Australia, Chile, Guatemala, New Zealand, Norway, Spain, the US and the UK

"Report I: Review of the Regulatory Framework" (January 18th, 1999). This report presents the options for a natural gas framework in Peru.

"Conceptual Framework for the Reform of the Electricity Sector in Mexico: White Paper" (November 24th, 1998). This report represents the White Paper for restructuring of the electricity sector in Mexico which is being used in Congress for debate.

"Precios del Gas Natural para la Generación de Electricidad en el Perú" (November 16th, 1998). This report analyzes different alternatives for the treatment of natural gas prices in the electricity tariff model (report in Spanish).

"Tariffs and Subsidies: Report for the Tariffs Group" (November 10th, 1998). This report presents recommendation on the path for tariffs and subsidies for 1999 to the Electricity Tariffs Group of the Government of Mexico.

"Gasoducto México-Guatemala: Informe Final" (October 22nd, 1998). This report analyzes the legal and regulatory framework in both Mexico and Guatemala and costs and volumes for the building of a natural gas pipeline connecting both countries. A copy of the report was given by President Zedillo (Mexico) to President Arzú (Guatemala) (report in Spanish).

"Checks and Balances in Regulating Power Pools: Seven case Studies. A Report for the Electricity Pool of England and Wales" (September 10th, 1998). This report surveys the regulation of power pools in electricity industries around the world.

"Fuels Policy Group: Recommendations" (September 11th, 1998). This report presents recommendations to the Government of Mexico on their fuels policies for the electricity sector.

"Análisis de Costos e Inversiones. Revisión Tarifaria de Transener" (August 25, 1998). Report given to ENRE (the Argentinean electricity regulator) on behalf of a Consortium of Generators on the analysis of costs and investments to be considered for the revenue requirement of the electricity transmission company (report in Spanish).

"Central America Pipeline: Regulatory Analysis and Proposal" (July 28, 1998). This report presents the regulatory analysis and development of a fiscal, legal and commercial framework proposal for gas import, transportation, distribution and marketing in El Salvador, Honduras and Guatemala regarding the proposed Central American Pipeline.

"Energy Regulation in El Salvador" (July 28, 1998). This report presents a deep analysis of the electricity and natural gas regulatory, legal and tax frameworks in El Salvador.

"Energy Regulation in Honduras" (July 28, 1998). This report presents a deep analysis of the electricity and natural gas regulatory, legal and tax frameworks in Honduras.

"Energy Regulation in Guatemala" (July 28, 1998). This report presents a deep analysis of the electricity and natural gas regulatory, legal and tax frameworks in Guatemala.

"The Cost of Capital for Gas Transmission and Distribution Companies in Victoria" (June 22, 1998). Report prepared for BHP Petroleum Pty Ltd.

RECENT INTERNATIONAL REPORTS (CONT.)

"Principios Económicos Básicos de Tarificación de Transmisión Eléctrica. Revisión Tarifaria de Transener" (May 26, 1998). The main purpose for this report was to provide an economic and regulatory analysis of laws, decrees, license and documents of the tender to provide advise in the tariff review of Transener (the electricity transmission company in Argentina), to present an economic analysis of transmission tariffs and to provide an opinion on specific topics to be discussed in the public hearing. This report was written for a consortium of generators in Argentina (reports in English and Spanish)

"Asesoría en la Fijación de Tarifas de Transener y Normativa del Transporte, Benchmarking Study" (May 26, 1998). This report compares the costs of Transener (the electricity transmission company in Argentina) with those of other companies elsewhere for a consortium of generators (the electricity transmission company in Argentina).

"International Regulation Tool Kit: Argentina" (March 20, 1998). This document describes the natural gas regulatory framework in Argentina for BG.

"Tarificación de los Servicios Que Prestan las Terminales de Gas LP" (January 9, 1998). The final report given to PEMEX Gas y Petroquímica Básica (México) for the determination of rates for LPG terminals.

"NERA-Pérez Companc Distribution Tariff Model" (January 5, 1998). This report explains the methodology behind NERA's calculations of distribution tariffs for Pérez Companc in Monterrey.

"Monterrey Natural Gas Market Assessment," (January 5, 1998). A series of reports were written to present the results of the market study of the demand for natural gas in the geographic zone of Monterrey to a company interested in bidding for the natural gas distributorship.

"Resolving the Question of Escalation of Phases (bb) and (cc) Under the Maui Gas Sale and Purchase Contract", prepared for the New Zealand Treasury, December 16, 1997.

"Timetable and Regulatory Review for the Monterrey International Public Tender," (December 5, 1997). A description of the necessary steps to bid for a distribution company as well as an explanation and analysis of natural regulations in Mexico for Pérez Companc.

"Economic Issues in the PFR for 18.3.1(I)(bb) & (cc)", prepared for the New Zealand Treasury, November 17, 1997.

"NERA's Distribution Tariff Model" (October 29, 1997). This report explains the methodology behind NERA's calculations of distribution tariffs for MetroGas.

"Evaluation Design Standards for MetroGas," (October 24, 1997). This report dealt with the analytical support resulting from work with MetroGas to create a meticulously-documented security criterion analysis that supported its efforts to obtain due recognition—and appropriate tariff treatment—for its costs.

"Ghana Natural Gas Market Assessment," prepared for the Ministry of Mines and Energy, Ghana (March-July, 1997). A series of four reports assessing prospective gas demand usage and netback prices for a number of proposed pipeline project alternatives.

"Final Report for Russian Oil Transportation & Export Study: Commercial, Contractual & Regulatory Component," prepared for The World Bank, June 25, 1997.

Response to FIEL's criticisms regarding NERA's report "Cálculo del Factor de Eficiencia (X)" (June 2, 1997).

RECENT INTERNATIONAL REPORTS (CONT.)

"Impacts on Pemex of Natural Gas Regulations" prepared for Pemex Gas y Petroquímica Básica México, May 21, 1997.

"Market Models for Victoria's Gas Industry: A Review of Options," April 1997, prepared for Broken Hill Proprietary (BHP) Petroleum, to propose an alternative model for gas industry restructuring in Victoria, Australia.

"New Market Arrangements for the Victorian Gas Industry," prepared for Broken Hill Proprietary Petroleum; March 13, 1997.

"CEG Privatization: Comments to the Regulatory Framework," prepared for Capitaltec Consultoria Economica SA describing our comments with respect to the regulatory framework and the license proposed in the privatization of Riogas and CEG in Rio de Janeiro, Brazil; March 7, 1997.

"Determination of the Efficiency Factor (X)," prepared for ENARGAS, Argentina, January 24, 1997.

"Determination of Costs and Prices for Natural Gas Transmission," prepared for Pemex Gas y Petroquímica Básica, México, December 19, 1996.

"Regulating Argentina's Gas Industry," a report prepared for The Ministry of Economy and The World Bank, November 26, 1996.

"Open Access and Regulation," prepared for Gascor, in the State of Victoria, Australia; (October 2, 1996).

"A Review and Critique of Russian Oil Transportation Tariffs (Russian Oil Transportation & Export Study; Commercial, Contractual & Regulatory Component)," prepared for The World Bank, June 13, 1996.

"Tariff Options for Transneft (Russian Oil Transportation & Export Study; Commercial, Contractual & Regulatory Component)," prepared for The World Bank, June 6, 1996.

"Comments on the Proposed Amendments to the Regulation of Airports in New Zealand," prepared for the New Zealand Parliament Select Committee hearings on the regulation of monopolies, March 13, 1996.

"Evaluating the Shell Camisea Project," prepared for Perupetro S.A., Government of Peru, December 8, 1995.

"Towards a Permanent Pricing and Services Regime," prepared for British Gas, London, England, November, 1995.

"Final Report: Gas Competition in Victoria," prepared for Gas Industry Reform Unit, Office of State Owned Enterprises, June 1995.

"Natural Gas Tariff Study," prepared for the World Bank, May 1995, consisting of:

Principles and Tariffs of Open-Access Gas Transportation and Distribution Tariffs
Handbook for Calculating Open-Access Gas Transportation and Distribution Tariffs

"Economic Implications of the Proposed Enerco/Capital Merger," prepared for Natural Gas Corporation of New Zealand, December 1994.

"Contract Terms and Prices for Transportation and Distribution of Gas in the United States," prepared for British Gas TransCo, November 1994.

RECENT INTERNATIONAL REPORTS (CONT.)

"Economic Issues in Transport Facing British Gas," prepared for British Gas plc, December 1993.

"Overview of Natural Gas Corporation's Open-Access Gas Tariffs and Contract Proposals," prepared for Natural Gas Corporation of New Zealand, October 1993.

RECENT SPEECHES

"A Gas Network to Meet the Needs of New Electricity Generators", Speech given before the Ontario Energy Association, Ontario, Canada, June 23, 2005.

"Forks in the Road for Electricity Transmission", Speech given at the Electricity Industry Regulation and Restructuring conference by The Salt River Project and The Arizona Republic, October 11, 2002.

"Role of Yardsticks in Cost & Service Quality Regulation", Speech to the London Regulated Industries Group, November 30, 2000.

"Natural Gas Issues: Retail Competition, LDC Gas Rate Unbundling, and Performance Based Rates", presented at the Wisconsin Public Utility Institute, November 17, 2000.

"Performance Based Ratemaking (PBR) in Restructured Markets, Speech to Edison Electric Institute Seminar in San Antonio Texas, April 27, 2000.

"Benchmarking versus Rate Cases and the Half Live of Regulatory Commitment", Speech given at the Australian Competition & Consumer Commission's Incentive Regulation and Overseas Development Conference, Sydney, Australia, November 19, 1999.

"Benchmarking, Rate Cases and Regulatory Commitment", Speech given at the Australian Competition & Consumer Commission's Incentive Regulation and Overseas Developments Conference, Sydney, Australia, November 14, 1999.

"Gas and Electricity Sector Convergence: Economic Policy Implications", Presentation at Energy Week '99, "The Global Shakeout", The World Bank, Washington D.C., April 6-8, 1999.

"Gas and Electricity Sector Convergence: Economic Policy Implications", Presentation/Training at the Economic Development Institute, The World Bank, Washington D.C., December 8-9, 1998.

"Sustainable Regulation for Russian Oil Pipelines", Presentation at Pipeline Transportation: A Linkage Between Petroleum Production and Consumers, Moscow, June 25, 1997.

"Rocks on the Road to Effective Regulation", Presentation to Brazil/US Aspen Global Forum, Aspen, Colorado, December 5-8, 1996.

"Stranded Cost Case Studies in the Gas Industry: Promoting Competition Quickly," —Speech presented at the MCLE Seminar: Retail Utility Deregulation, Boston, MA, June 17, 1996.

"Why Regulate Anyway? The Tough Search for Business-As-Usual Regulation,"—Panelist at St. Louis 1996, The Fifth Annual DOE-NARUC Natural Gas Conference, St. Louis, Missouri, April 30, 1996.

"Antitrust for Utilities: Treating Them Just Like Everyone Else"—Panelist at St. Louis 1996, The Fifth Annual DOE-NARUC Natural Gas Conference, St. Louis, Missouri, April 29, 1996.

"Natural Gas Pricing: The First Step in Transforming Natural Gas Industries"—One-Day Interactive Workshop on Pricing Strategy at The Future of Natural Gas in the Mediterranean Conference, Milan, Italy, March 27, 1996.

"Open Access in Gas Transmission,"—Speech given at the New England Chapter of the International Association for Energy Economics, Boston, Massachusetts, December 13, 1995.

"Light-Handed Regulation for Interstate Gas Pipelines,"—Speech given at the Twenty-Seventh Annual Institute of Public Utilities Conference, Williamsburg, Virginia, December 12, 1995.

RECENT SPEECHES (CONT.)

"Ending Cost of Service Ratemaking,"—Speech given to the Electric Industry Restructuring Roundtable, Boston, Massachusetts, October 2, 1995.

"Promoting Markets for Transmission: Economic Engineering or Genuine Competition?"—Speech given at The Forty-Ninth Annual Meeting of the Federal Energy Bar Association, Inc., May 17, 1995.

"End-Use Competition Between Gas and Electricity: Problems of Considering Gas and Electric Regulatory Reform Separately,"—Panelist on panel at ORLANDO '95, The Fourth Annual DOE-NARUC Natural Gas Conference, Orlando, Florida, February 14, 1995.

"Incremental Pricing: Not a Quantum Leap,"—Speech given at the 1995 Natural Gas Ratemaking Strategies Conference, Houston, Texas, February 3, 1995.

"The Feasibility of Competition in the Interstate Pipeline Market,"—Speech given at the Institute of Public Utilities Twenty-Sixth Annual Conference, Williamsburg, Virginia, December 13, 1994.

"A Mirror on the Evolution of the Gas Industry: The Views from Within the Business and from Abroad,"—Speech given at the 1994 LDC Meeting-ANR Pipeline Company, October 4, 1994.

"Creating New Markets Out of Old Utility Services," —Speech given at the Fifteenth Annual NERA Santa Fe Antitrust and Trade Regulation Seminar, Santa Fe, New Mexico, July 9, 1994.

"Sources of and Prospects for Privatization in Developed and Underdeveloped Economies," —Speech given at the Spring Conference of the International Political Economy Concentration and the National Center for International Studies at Columbia University, New York, March 30, 1994.

"Experiencias en el Desarrollo del Mercado de Gas Natural (Experiences in gas market development)," —Speech given at the conference "Perspectivas y Desarrollo de Mercado de Gas Natural," Centro de Extensión de la Pontificia Universidad Católica de Chile, November 16, 1993.

"The Role of Rate of Return Analysis in a More Progressive Regulatory Environment,"—Speech given at the Twenty-Fifth Financial Forum held by the National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 27, 1993.

"Privatization of Energy and Natural Resources,"—Speech given at the International Privatization Conference "Practical Issues and Solutions in the New World Order," New York, New York, November 20, 1992.

PARTIAL LIST OF CLIENTS SERVED WORLDWIDE

ELECTRIC UTILITY

AEP Energy Services, Inc
Alberta Power Limited
American Electric Power Company
Atlantic Electric Company
Boston Edison Company
Central Hudson Gas and Electric
Central Maine Power Company
Central Power & Light Company
Commonwealth Edison Company (Unicom/Exelon)
Commonwealth Energy System
Consolidated Edison Company of New York, Inc
Conowingo Power Company
Duquesne Light Company
Edison Electric Institute
Entergy Gulf States, Inc
Florida Power and Light Company
Green Mountain Power Company
Long Island Lighting Company
Massachusetts Municipal Wholesale Electric Company
Massachusetts Electric Company
Nantahala Power Company
New York State Electric & Gas Corporation
Niagara Mohawk Power
Ohio Power Company
Orange & Rockland Utilities
Pennsylvania Power and Light Company
Pennsylvania Power Company
Philadelphia Electric Company
PJM electricity transmission owners
Public Service Company of New Hampshire
Public Service Company of New Mexico
Public Service Electric and Gas Company
Portland General Electric Company
Reliant Energy HL&P
Rochester Gas and Electric Corp.
Sierra Pacific Power Corporation
Southwest Electric Power Company
Southwestern Public Service Company
Tampa Electric Company
Texas-New Mexico Power Company
TXU Electric Company
United Illuminating Company
UtiliCorp Networks Canada
Virginia Electric and Power Company
West Penn Power Company
West Texas Utilities Company
Western Massachusetts Electric Co.

GAS UTILITY

ARKLA, Inc.
Atlanta Gas Light Company
Bay State Gas Company
Berkshire Gas Company
Blackstone Gas Company
Boston Gas Company
Bristol & Warren Gas Company
British Gas plc
Brooklyn Union Gas Company
Canadian Western Natural Gas
Chattanooga Gas Company
Colonial Gas Company
Commonwealth Gas Company
Connecticut Natural Gas Corp.
Consolidated Gas Supply Corp.
Elizabethtown Gas Company
Empire State Pipeline Company
ENAGAS (Spain)
EnergyNorth, Inc.
Essex County Gas Company
Fall River Gas Company
Fitchburg Gas & Electric Light Company
Gas and Fuel Corporation of Victoria
Gateway Pipeline Company
Granite State Gas Transmission, Inc.
Great Falls Gas Company
Holyoke, Mass. Gas & Electric Dept.
ICG Utilities (Ontario) Ltd.
KN Energy, Inc.
Middleborough Municipal Gas & Electric
National Fuel Gas Distribution Corp.
Natural Gas Corporation of New Zealand
Natural Gas Pipeline of America
Norwich Department of Public Utilities
Pacific Gas Transmission
Pemex Gas y Petroquímica Básica
Pennsylvania Gas and Water Company
Peoples Gas Light and Coke Company
Providence Gas Company
Southern Connecticut Gas Company
Southwest Gas Corporation
Transwestern Pipeline Company
Valley Gas Company
Washington Gas Light Company
Westfield Gas & Electric Light Dept.
Wisconsin Gas Company
Yankee Gas Services Company

PARTIAL LIST OF CLIENTS SERVED WORLDWIDE (CONT.)

TELEPHONE UTILITY

Centel Corporation
Chichester Telephone Company
Community Service Telephone Company
Continental Telephone Company of Illinois
General Telephone of Pennsylvania
General Telephone Company of Ohio
Kearsarge Telephone Company
Meriden Telephone Company
Pacific Bell Telephone Company
Tipton Telephone Company

PARTIAL LIST OF CLIENTS SERVED WORLDWIDE (CONT.)

REGULATORY AND GOVERNMENT

Delaware Public Service Commission
re: Delmarva Power & Light Company

District of Columbia Public Service Commission
re: Potomac Electric Power Company
Washington Gas Light Company

Massachusetts Municipal Wholesale Electric Company

The Government of Chile
Gas industry regulations

The Government of Argentina
Plan for privatized rail freight industry regulation

The Government of Tanzania
Natural gas development and regulation plan for Songo Songo Island gas reserves.
Financing the development of gas reserves on Songo Songo Island with emphasis on payment guarantee mechanisms for foreign exchange.

The World Bank
re: Natural gas tariffs for Polskie Gornictwo Naftowe i Gazownictwo (The Polish Oil and Gas Company)

re: Natural gas transport and distribution tariffs for Gas del Estado (The Argentine State-owned gas utility)

re: Natural gas development for the Moroccan Gas System.

re: Natural gas transport and distribution tariffs for the Bolivian Gas Industry.

re: Natural gas development plan for Sichuan province of China.

OTHER

Air New Zealand
BHP Petroleum Pty Ltd
Centel Corporation
General Electric Company
Intel Corporation
Jamaica Water Supply Company
Nucor Steel Corporation
Parsons Brinckerhoff Development Group

MEMBERSHIP IN PROFESSIONAL ORGANIZATIONS

The American Economic Association

Credit Rating Agency Quotations

While the presence of FACs have always been noteworthy in ratings agency reports for the electric utility sector, the greater volatility of the wholesale power markets has caused them generally to heighten their focus. This was especially true during and after the Western-US energy crisis. In terms of fuel adjustment clauses and utility credit quality, *S&P* states:

> Standard & Poor's is frequently asked what weight is given to FPPA. It is clear that continued gas price volatility and upward trends in historically stable coal prices underscore the importance of FPPAs....to the extent that an FPPA is transparent and well structured, regulators are likely to be less inclined to disallow a utility's fuel and purchased-power costs.[1]

Fitch Investor's Service (formerly *Duff & Phelps*) discusses the extreme adverse consequences of a state not enacting an FAC:

> California remains an extreme example of what can go wrong when FACs are eliminated, rates are frozen, and regulators are either unable or unwilling to extend support to local utilities.[2]

Three years after the Western-US energy crisis, *S&P* stated the following:

> It has been more than three years since the California energy crisis led to the rapid deterioration of credit quality for many Western electric utilities...The severe market distortions of the California crisis have faded, but FPPAs continue to play a significant role in the financial well-being of western electric utilities. Natural gas volatility, poor hydro conditions in the Northwest, the Southwest's sustained drought, and uncertainty over future generation development are daily reminders that **it is increasingly difficult for utilities to sustain their financial health solely through the use of hedging policies and regular general rate case filings** [emphasis added][3]

Fitch also discusses the effect of an FAC on an IOUs bond rating:

> In today's environment, the safest bonds in the utility industry may be those of vertically integrated utilities operating under commission-approved mechanisms to recoup prudently incurred power costs. Such companies typically operate in

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1 *Standard & Poor's* "Fuel and Power Adjusters Underpin Post-Crisis Quality of Western Utilities," October 14, 2004.

2 *Fitch*, "Natural Gas Price Sensitivity of the U.S. Utility Sector," July 1, 2004, p. 7.

3 *Standard & Poor's* "Fuel and Power Adjusters Underpin Post-Crisis Quality of Western Utilities," October 14, 2004.

> supportive regulatory environments which continue to feel the need for healthy reserve margins of generation.[4]

In terms of handling fuel volatility, *Moody's* states that:

> Regulated vertically integrated utilities operating without regulatory recovery of potentially high electricity costs from spot-market purchases are equally vulnerable, particularly during periods of peak energy demand and/or supply shortages.... Moody's ultimately believes that companies exposed to supply risk must demonstrate the ability to appropriately hedge this risk in order to preserve its financial integrity and maintain its bond rating.[5]

In terms of natural gas price sensitivity of the U.S. Utility Sector, *Fitch* states that:

> The high price of natural gas and the increased price volatility witnessed during the past three years have presented challenges of varying degrees to issuers in U.S. electric and gas coverage. The ability of these companies to manage commodity price exposure varies considerably among firms within the sector and is an important rating factor.... However, integrated utilities with the obligation to serve and no adequate fuel cost recovery mechanism, as well as electric distributors operating under frozen rate tariffs that are required to defer power purchases, are generally more exposed to volatile commodity prices.[6]

In 1998, *S&P* noted that "[a]utomatic pass-through mechanisms that hold companies harmless from uncontrollable costs, such as fuel or foreign exchange effects, are viewed favorably."[7]

With respect to integrated utility companies, *Fitch* states,

> Although a majority of integrated utilities remain substantially protected from fluctuating commodity price levels due to the existence of fuel/purchased power adjustment clauses (FACs), a handful of companies possesses regulatory mechanisms that offer only partial protection while others lack such a clause altogether.... Unless a protective adjustment mechanism is in place, utilities purchasing power from the spot market to meet load requirements will be particularly exposed to high costs during periods of high demand, when gas is likely to be on the margin in all U.S. regions.[8]

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4 *Fitch*, "Procuring Power in California: A Potential Stranded Cost," September 7, 2000, p. 4.

5 *Moody's Investors Service*, "Credit Implications of Power Supply Risk," July 2000, p. 3.

6 *Fitch*, "Natural gas Price Sensitivity of the U.S. Utility Sector," July 1, 2004, p. 1.

7 *Standard & Poor's*, "Rating Methodology For Global Power Utilities," *Standard & Poor's Infrastructure Finance*, September 1998, p. 66.

8 F*itch*, "Natural gas Price Sensitivity of the U.S. Utility Sector," July 1, 2004, p. 4.

Moody's mirrors *Fitch's* sentiments by stating:

> Regulated vertically integrated utilities operating without regulatory recovery of potentially high electricity costs from spot-market purchases are equally vulnerable, particularly during periods of peak energy demand and/or supply shortages.... Moody's ultimately believes that companies exposed to supply risk must demonstrate the ability to appropriately hedge this risk in order to preserve its financial integrity and maintain its bond rating.[9]

With regard to Provider of Last Resort service in restructured states, *Moody's* states that:

> In general, utilities have little incentive to accept the financial risk PLR service creates without being compensated by regulators with some form of pass-through. Each state will determine its own plan, and Moody's believes that elements of a purchased power adjustment clause will be retained for PLR service.[10]

These are typical passages from ratings agency reports in the era of competitive power markets. The ability of electric utility companies to charge compensatory rates in light of changing wholesale power costs is of key importance in assessing the risk to which investors expose their capital.

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[9] *Moody's Investors Service*, "Credit Implications of Power Supply Risk," July 2000, p. 3.

[10] *Id.*, p. 3.

TESTIMONY OF
EUGENE T. MEEHAN

On Behalf of
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Fuel Hedging Overview

SECTION 1: INTRODUCTION

Q. Please state your name and business address.

A. My name is Eugene T. Meehan. I am Senior Vice President at National Economic Research Associates ("NERA"). My business address is 1255 23 St. NW, Washington, DC 20037.

Q. Please summarize your professional qualifications.

A. I have over twenty-five years of experience consulting with electric and gas utilities. That work has involved examination and advice on many issues related to power markets, power contract design, utility fuel and purchased power procurement and hedging, competitive bidding and contract evaluation. For the past ten years, I have been extensively involved in advising clients on restructuring-related issues, including risk analysis, risk management, power plant and power contract valuation, and post-transition regulatory issues. In the past few years, I also have advised several utilities with respect to the acquisition of power from third parties. These assignments have involved the review of power contract offers made by competitive power marketers and owners of generation assets. Additionally I have testified several times with respect to the prudence of utility planning and power procurement. HECO-2200 contains a more detailed statement of my qualifications.

Q. Will you briefly describe the nature of NERA's business?

A. NERA is a firm of over 450 professional economists located in offices throughout the United States, Europe, Asia and Australia. NERA provides consulting advice in litigation and regulatory settings, as well as strategic and planning advice to clients in the energy, telecommunications, television and broadcasting, securities, transportation, health and banking industries.

Q. Please describe the scope of your testimony.

A. I was asked by Hawaiian Electric Company, Inc. ("HECO") to address the possibility of fuel price hedging by HECO in response to Act 162 ("the Act"), which was signed into law in Hawaii on June 2, 2006. My testimony provides a summary of the type of fuel price hedging that potentially could be performed by HECO in the marketplace and an assessment of the potential impacts of fuel price hedging on HECO, its customers and the regulatory ratemaking process that are undertaken before the Hawaii Public Utilities Commission.

Q. Please provide a definition of hedging.

A. The Edison Electric Institute (EEI) defines hedging as "the attempt to eliminate at least a portion of the risk associated with owning an asset or having an obligation by acquiring an asset or obligation with offsetting risks."[1] Hedging can, in principle, allow a utility to offset and reduce risk as it procures fuel and purchased power on behalf of its customers.

Q. Can you describe HECO's current oil procurement practices?

A. Yes. HECO generates electricity primarily by burning oil. To ensure a reliable physical supply of oil HECO has a variety of oil supply contracts that provide for it to obtain fuel oil delivered to its plants that is physically and environmentally suitable to burn at each plant. These contracts call for HECO to pay a price each month based on contract formulas. The key factor affecting these formulas is the relevant oil index on a daily basis over the month. The oil index is the reported market price of transactions in a standard oil product at a particular location. For example, HECO burns low sulphur residual oil in its larger steam plants. The contract for that product is tied to the daily index for Singapore/Indonesia cracked

[1] EEI Glossary of Electric Industry Terms, April 2005.

low sulphur waxy residual oil. This is a sensible index as it is economic for HECO's supplier to acquire such oil to meet HECO's needs and as HECO's supplier will want to sell at a market price.

Purchasing oil at a formula rate tied to oil products that are traded in the worldwide oil market, means that HECO's fuel costs will vary with world oil prices. It also means that HECO's fuel supplier is not taking world oil price risk and can offer HECO a price free of a world oil price risk premium. Thus, HECO can offer its customers a price for electricity that is free of any risk premium associated with bearing world oil price risk.

Q. How does this relate to Act 162?

A. Act 162 raises the question of whether HECO should hedge by reference to "fuel hedging contracts" as a commercially available means to mitigate the risk of fuel price changes.[2] Hedging with respect to energy commodities can take two forms: (i) physical hedges, such as physical supply contracts and fuel inventories; and, (ii) financial hedges, such as fixed-price financially-settled futures contracts and financial options contracts. HECO could, in theory, hedge fuel by buying financial products called oil price futures. Were HECO to buy oil price futures, it would realize profits when oil prices rose and losses when oil prices dropped. This is a hedge, because the gain or loss is opposite in direction to what HECO pays for oil under its contracts. For example, assume an oil price future for next July was available at $70 per barrel. HECO will buy oil next July at the formula rate. If HECO bought a future now at $70 and prices in July dropped to $50, HECO would lose $20 per barrel. However, it would only pay $50 in July. The loss would offset or hedge the actual purchase cost. If, on the other hand, the

[2] Act 162, (g) (iii).

price rose to $100 in July, HECO would actually pay $100 for oil at the time. However, if it had hedged by purchasing a $70 future, it would realize a $30 per barrel profit that would offset its actual purchase cost. That profit is a hedge. Hedges are accomplished using financial instruments called derivatives. They are called derivatives, because their value is derived from the market price of an underlying commodity. An oil future, for example, is settled against the price of oil and is an oil derivative. HECO would buy derivatives and the value of these derivatives would rise when HECO's actual contract purchase costs rose and fall when HECO's actual contract purchase costs fell. Thus, they would offset or hedge actual contract purchase costs.

Q. What factors may prevent hedging from achieving the goal of safe, adequate and reliable service at the lowest reasonable cost?

A. There are four factors to consider:

- *Downward price movements may be foregone.* Locking in a price for oil today or at some fixed point for delivery in the future does not provide for a lower price, just a known price. The price locked in may well be higher than the price in the future at which HECO actually purchases oil. Hence, hedging does not provide for lower prices. It only increases predictability, which may not be perceived as beneficial by all customers.
- *Hedging involves costs.* These costs are incremental to the fuel acquisition costs when fuel is not hedged. Customers can expect to pay more if HECO adopts fuel hedging. It is not at all clear that increased predictability is worth the extra costs.
- *Hedging is imperfect.* The example of a single barrel of oil selling for $50, $70 or $100 is a simplification of the actual situation facing HECO. Perfect

hedges can only be accomplished when the hedged product is identical to the acquired product and when the volume needed by the hedger is certain. HECO could not buy derivatives that correspond exactly to the product that will be acquired. It would need to hedge using similar, but not identical, products. This poses what is called basis risk. Basis risk is the difference in price movement between the derivative used to hedge and the price movement in the product that will actually be bought. In HECO's case basis risk is substantial because the indexes in HECO's oil contracts are not traded in the most liquid and transparent derivatives markets and because the closest substitutes are only traded in less liquid and less transparent derivative markets. When a regulated utility hedges, it is best done in transparent liquid markets. The products available in the transparent and liquid oil derivative markets, however, do not move in lock step with the indexes in HECO's contracts. Further, HECO pays for oil based on average daily prices in the indexes. If HECO were to hedge, it would settle once a month and this itself would create a basis difference between the derivative used and HECO's actual costs. This basis difference means that if HECO were to attempt to hedge it could only partially hedge. Its hedges would not be fully effective. I have looked at several years of historic data and have found that this is not just an academic issue. HECO would have a difficult time placing effective hedges.

- *Limited duration of financial hedges.* HECO could hedge oil prices at most for a year out in the future. Hence, while there may be an enhanced degree of price predictability, it would be for a limited time and would not protect customers against long term trends in oil prices.

Q. With these factors in mind, what do you conclude?

A. My conclusions with respect to fuel price hedging are as follows.

(1) Even if rate smoothing is a desired goal, there may be more effective means meeting the goal. There is no compelling reason for HECO to use fuel price hedging as the means to achieving the objective of increased rate stability.

(2) While HECO could partially hedge against oil price risk for periods of just over a year into the future, there would be considerable costs to doing so. The liquidity of standard financial hedging products with a term of over a year is limited. Given this, price hedging should not be expected to address rate periods of more than one year at a time.

(3) Were HECO to hedge, it would at best be able to partially hedge as there are considerable differences in price fluctuations between the hedges HECO could readily purchase and the cost of the oil it burns. Further, the exact volume of oil needed is not knowable with certainty. Moreover, prices should signal costs. While some customers may desire rate stability and predictability, and be willing to pay, others may not be willing to pay for predictability. One way to deal with this issue would be to allow customers to “opt in” to rate stability programs, such as hedging initiatives, that may be expected to raise average overall costs to customers.

(4) Were HECO to hedge, it would encounter periods during which it experienced gains on its hedges and other periods during which it experienced losses. The gains in large part would be offset by increased fuel purchase costs and the losses in large part would be offset by reduced fuel purchase costs. The ECAC framework would need to be revised so that the difference between the gains and increased fuel costs and the difference

between the losses and reduced fuel costs were reflected in rates through the ECAC.

(5) Hedging of oil by HECO would not be expected to reduce fuel and purchased power costs and in fact would be expected to increase the level of such costs.

(6) It would not be reasonable for HECO to take the position of a principal and speculate in the oil market with shareholders assuming the risk of oil derivative gains and losses.[3]

Q. Please explain the basis for your first conclusion that if increased rate stability is the objective, there is no compelling reason to achieve this by fuel hedging.

A. The basis for this conclusion is rooted in the fact that hedging carries a limited scope of benefits, and also implies costs and risks for customers.

The scope of benefits from hedging is limited by the realities of the oil hedging marketplace and HECO's physical location. First, the duration of any benefit is limited: the markets do not offer reasonable hedging solutions that would permit HECO to manage oil price-driven rate fluctuations for more than one year at a time. Second, there is no *ex ante* expected price benefit. Even if hedging can stabilize purchased oil prices to some degree, the stabilized price may be higher or lower than the price that would have been achieved absent the hedging program. On average, costs can be expected to be higher with a hedging program. Third, the amount of fuel cost stability that can be achieved is uncertain due to basis risks, quantity risks and other risks. HECO cannot enter into readily-traded fuel hedging contracts that eliminate all exposure to oil price fluctuations; such

[3] Derivatives are a term used to describe financial instruments whose value is derived from the price of an underlying commodity. Hence, an oil price swap is a derivative as its value is based on the price of oil, the underlying commodity.

contracts do not exist in the marketplace. The risks inherent in available fuel hedging contracts create uncertainties as to how effective hedging products would be in stabilizing prices for customers. The cost of bearing these risks is potentially high.

Further, HECO may be able to achieve increased short-term rate stability more effectively through the ratemaking process. My colleague, Dr. Jeff Makholm, discusses these alternatives in HECO T-21.

Q. Please explain the basis for your second conclusion, that price hedging could not be performed for periods of greater than one year and that hedging could not eliminate all fuel price risk for HECO's customers.

A. My conclusion that it is not reasonable for HECO to enter into hedges of greater than one year is based primarily on my analysis of the oil hedging market. I examined the types of price-risk management contracts that are available through the over-the-counter market and exchange markets. I found that the contracts that are most actively traded are the contracts for very near term deliveries, *i.e.*, delivery within the next three to six months. In addition, I found some trading of contracts for deliveries covering six to eighteen months in the future. For deliveries in periods beyond eighteen months in the future, trading is very thin or non-existent.

The most liquid exchange-traded contracts that would be available to hedge the fuel needs of HECO and its affiliates are the New York Mercantile Exchange ("NYMEX") heating oil futures contract based on pricing at New York Harbor, the NYMEX West-Texas Intermediate crude oil futures priced at Cushing, Oklahoma, and the Intercontinental Exchange ("ICE") Brent crude oil futures priced at Sullom Voe in the North Sea. To illustrate how trading drops off for longer-dated delivery periods for these contracts, I have provided as HECO-2201 an example of the daily trading volume, open interest and forward prices for each futures contract.

HECO-2201 illustrates how liquidity is concentrated in the near-term delivery months. Hedging with contracts that are thinly traded poses risks and tends to be more expensive. Given the trading activity for these futures markets, it would not be reasonable to expect HECO to hedge beyond 12 months into the future. It is important to recognize that there are higher liquidity risks associated with the longer-dated contracts, and there would be liquidity risks and illiquidity premiums even within the eighteen-month time horizon.[4]

Q. Please explain the basis for your third conclusion, that were HECO to hedge it would at best be able to partially hedge.

A. Based on my review of HECO's existing physical fuel contracts and my review of available price hedging products in the marketplace, HECO would not be able to eliminate all of the risk of oil price fluctuations. The fuel contracts contain complex pricing provisions that are based in part on published fuel assessments, but also contain adjustments for product quality and in some cases freight costs. This means that even if HECO were able to hedge the published assessment, the final cost of delivered oil would remain subject to residual price risks that could not be hedged.

Further, my review of the over-the-counter oil derivatives markets turned up no visible contracts for the specific fuel assessments that are referenced in HECO's fuel supply contracts. As I have explained above, this means that HECO would have to bear the basis risks or pay a premium to shift those risks to a third-party

[4] From a regulatory standpoint, great care would be necessary to judge hedging costs based on what would have been known by a reasonable utility at the time that the decisions were made.

via a customized swap, which may be expected to increase average costs for customers.

Moreover, the fuel hedging contracts that are available in the marketplace are for fixed quantities. HECO's customers would therefore bear market risk exposure for incremental or decremental quantities relative to the fixed quantity that is hedged by HECO.

All of these factors imply that even with a short-term price hedging program, there would still be fluctuations – potentially large fluctuations – in HECO's cost of fuel.

Q. Please explain the basis for your fourth conclusion, that price hedging would create gains and losses and that these gains and losses would need to be flowed through the ECAC mechanism.

A. Gains and losses are a natural part of hedging. Through its price hedging activities, HECO would effectively be using forward contracts to lock in a price for oil for delivery periods in the future. If prices for those delivery periods rise subsequent to HECO's having locked in its price, HECO will experience a gain on its hedge. If prices fall subsequent to placing its hedge, HECO will experience a loss. The mechanics of financial settlement of the hedges are such that any differential between the forward price locked in and the price at maturity would be multiplied by the fixed quantity that HECO had hedged to arrive at a settlement cost for the contract. The hedging contracts will create gains and losses, but as noted, those gains and losses will be partially offset by changes in the cost of delivered oil.

The net result is that HECO would continue to experience variable net fuel and hedge costs even with a hedging program. In HECO T-21, Dr. Jeff Makholm elaborates on the reasons why it is important to flow through the net fuel costs (i.e., fuel costs adjusted for hedge gains and losses) in an ECAC.

The reasons cited by Dr. Makholm for flowing through the cost of purchased oil through the ECAC are also applicable to hedging costs. Further, if hedging is pursued, it will be important for HECO and the Commission to agree on the objective of hedging, an acceptable hedging program, including the specification of approved contract types and contract duration, an approved timescale for hedge execution, as well as the revisions to the ECAC cost recovery framework.

Q. Please explain the basis for your fifth conclusion, that price hedging by HECO would not be expected to reduce fuel and purchased power costs and in fact would be expected to increase the level of such costs.

A. Utilities are not in the business of predicting world oil prices and cannot be expected to consistently buy low. If fuel hedging contracts are entered into by HECO, there will be no way to know on an *ex ante* basis whether market prices will move up and those hedges will lower rates for customers or whether market prices will move down and those hedges will raise rates for customers. There are certain explicit costs to hedging, and if pursued, HECO would face new risks that it does not currently face. I have elaborated the costs and risks of hedging in HECO-2202, which I will describe in more detail later in my testimony. These risks and costs lead to fuel costs from hedging that can be expected on average to be higher. The trade-off is an expected increase in rate stability at the cost of higher expected costs.

The notion that hedging is costly and can be expected to raise rates is cited by the National Regulatory Research Institute ("NRRI"):

> Hedging, in its purest form, does not provide a means to reduce the

expected price of gas for a utility. Rather, from the consumers' perspective its primary function is to stabilize prices. Generally, risk-adverse consumers should be expected to pay extra for shouldering less risk, such as exposure to volatile prices

Q. Please explain the basis for your sixth conclusion, that HECO should not engage in hedging as a principal and place shareholder funds at risk.

A. The motivation for hedging would be to provide rate stability for customers. HECO would thus be entering into hedges on behalf of customers, not on its own behalf. It is logical that customers bear the risks and rewards of hedging. Under the regulatory bargain, shareholders bear certain risks and reap certain rewards. However, gains or losses on hedges that were entered into on behalf of customers under the direction of the Commission should not be shareholder responsibility. My colleague, Dr. Makholm, explains why having the utility share in the risk of input costs when the utility is purchasing in world markets and is a price-taker is contrary to sound regulatory practice and would violate the regulatory bargain.

Q. Please describe how your testimony is structured.

A. In Section 2, I provide an overview of hedging and the reasons why firms choose to hedge. In Section 3, I describe HECO's current oil positions and existing hedges and explain the risk mitigation function that those hedges serve. Section 4 addresses several alternatives for hedging price in the marketplace, specifically explaining forward contracts, call options and collars. In Section 5, I explain the realities of the marketplace for oil derivatives and the costs and risks of entering into fuel hedging contracts.

SECTION 2: BACKGROUND AND OVERVIEW OF HEDGING ON BEHALF OF UTILITY CUSTOMERS

Q. What types of hedging does your testimony address?

A. I assess price hedging for liquid fuels used by HECO to generate electricity. As I explain below, HECO already engages in physical hedging through its supply contracts.

Q. Based on your experience and knowledge of hedging and its implementation, please address the duration of hedging contracts. Are hedging contracts by nature short-term or long-term?

A. In regulatory parlance and in many industries, the term "hedging" most often refers to short-term activities. By short-term, I mean a year in duration or less. This is because forward markets offer liquid price hedging contracts covering delivery periods that often extend only for one or two years forward. For the oil derivatives markets, price hedging contracts are only reasonably available for periods of up to twelve months. This means that hedging contracts, if pursued by HECO, could only mitigate the impacts of oil price changes on costs and rates for a defined period such as one quarter or potentially one year. Fuel hedging contracts could not be expected to cover durations longer than this.

Long-term hedging – i.e., hedging for more than one year in the future – cannot reasonably be achieved through commercially available fuel hedging contracts. Long-term hedging for HECO would require investment in non-oil based generation capacity, either through rate-based generation or through long-term contracts with non-utility generators.

Q. Does your testimony address short-term or long-term hedging?

A. My testimony primarily addresses short-term hedging, as this is my understanding of what should be examined as a result of the language in the Act that refers to commercially available fuel hedging contracts. The only fuel hedging contracts that are available in the marketplace are by nature short-term. Long term hedging could not be accomplished with commercially available fuel hedging contracts, and is more appropriately considered resource diversification.

Q. Is hedging necessarily beneficial?

A. No. It depends on the objective of the entity engaged in the hedging. Hedging is most often done to lock in a range of outcomes and not to maximize expected value. In fact hedging reduces the expected value of profitability and raises the expected value of costs. Hedging can be beneficial to a firm that seeks to reduce the range of potential outcomes, but hedging creates costs and risks. .

Q. Under what specific circumstances might hedging be appropriate?

A. There are certain situations where firms face business or financial risks that make hedging particularly important. For example, if prices for the firm's product will remain relatively fixed as a significant input cost varies, then hedging that input cost may be necessary to protect cash flows and maintain financial stability. This will be the case when the firm is more reliant on a specific commodity than the industry in general and changes in that commodity's price do not have a proportional impact on market prices. This could also be the case when industry competitive pressures are so severe that product prices cannot rapidly adjust to meet changes in input costs.

Q. How does hedging differ from speculation?

A. Speculation is defined as taking a position with the intent to profit from a change in the price of the underlying commodity. Hedging differs from speculation in that hedging is intended to insulate profits from the effect of changes in the underlying commodity. Hedging is the polar opposite of speculation. Some activities deemed to be hedging by unregulated firms are actually speculation. This is the case when the firm seeks to profit from a change in the price of the underlying commodity as opposed to holding itself neutral to such a change.

Q. Why would a regulated utility engage in hedging?

A. The motivation for regulated utilities to hedge is different from the motivation of firms in competitive industries. Regulated utilities with highly variable fuel costs generally have fuel adjustment clauses in place that provide for timely and adequate recovery of costs.

Hedging by regulated utilities is oriented toward managing customer rates; its objective is to insulate customers from the price fluctuations in an underlying commodity. For example, some gas and power distribution utilities hedge the commodities they sell in order to provide a fixed- or near-fixed price to customers. It only makes sense to hedge if the intent is to sell at fixed or near fixed rates.

Q. What do you mean by the term "near fixed rates"?

A. In my experience it is very unusual for electric utilities to offer rates that do not fluctuate based on changes in fuel and purchased power markets. This can mean rates that fluctuate monthly, which gives customers an economically-desirable price signal to reduce usage when power costs go up. It can also, however, mean rates that are near fixed, in that they are set for a period of time and differences are reconciled on a semi-annual or annual basis. In these circumstances, a utility may attempt to minimize differences by hedging with fixed price purchased power contracts or fuel hedges. I use the term near fixed rates as even in cases where a utility hedges, the rates are not completely fixed. Utilities are not well positioned to offer fixed rates and even in instances where they may engage in some hedging, the rates are at most near fixed as opposed to fixed as perfect hedging is unachievable.

Q. In your experience, when regulated firms decide to engage in hedging programs, what is the degree of regulatory oversight of these programs?

A. My experience has been that hedging programs are designed and implemented by utilities in collaboration with the commissions that regulate them. The utilities agree upon an objective with the regulator and then they clearly establish a program for achieving that objective. The need for a regulated entity to hedge is created by a specific and customer focused objective not by the economics of the regulated business model. Therefore it must involve considerable regulatory oversight and guidance.

Q. Do regulated utilities hedge in order to obtain the best or lowest possible price for fuel?

A. No. That would not be hedging, it would be speculating. Any fuel hedging program with the objective of "timing the market" and "buying low," is not a hedging program. Utilities have no specialized expertise in identifying trends in world oil markets and cannot be expected to predict market high and low points. That job is left to professional traders and speculators. A utility should not be asked to speculate on behalf of its customers. Moreover, a utility should not bear any financial risk or reward related to the timing of hedge execution. Utilities hedge to lock in a current market price and reduce fluctuations and not to minimize fuel acquisition costs.

Q. How should HECO and the Commission go about exploring hedging?

A. HECO is required by Act 162 to explore hedging. I recommend that HECO explore hedging while recognizing the following:

1. There is no business reason for HECO to hedge and the benefits to customers are unclear;
2. Fuel (oil) hedging by HECO will be expected to result in increased customer costs and as such should only be seriously considered if there is a countervailing benefit;
3. Fuel hedging by HECO may be able to reduce oil price-induced fluctuations in customer rates, but would not eliminate such fluctuations. Hence while rate stability may be a countervailing benefit to the costs of hedging, hedging will provide, at best, *more* and not *absolute* rate stability;
4. Fuel hedging objectives, if fuel hedging were to be implemented, would need to be developed in close consultation with regulators and customers and approved a priori as hedging by HECO would be on behalf of customers and not for HECO's shareholders account; and,
5. If HECO were to implement fuel hedging it should not speculate by attempting to time the market to minimize oil purchase costs.

Further, I would recommend that HECO carefully consider limitations on its ability to hedge that are a function of marketplace realities and the implications of hedging on its financial position. I will describe these factors in later sections of my testimony.

SECTION 3: BACKGROUND ON HECO'S CURRENT OIL POSITIONS AND EXISTING HEDGES

Q. Please describe HECO's current oil positions and its existing hedge contracts.

A. In order to meet the electricity demands of its customers, HECO operates oil-fired power plants. HECO purchases the oil for these plants. HECO's position in oil is therefore a short physical position. HECO hedges its short physical position by entering into an offsetting long position in delivered oil. This long position is achieved through the Company's existing fuel supply contracts. These fuel supply contracts tie the price paid by HECO for oil to a base component. The base component is the month-to-date average of a third-party assessment calculated on the 20th of the month before delivery. For example, HECO's industrial fuel oil deliveries for January 2007 will be based on the average of the Platts Los Angeles Bunker C assessments from November 21st to December 20th 2006. The actual contract price includes taxes and a standard premium (based on quantity). Depending on the contract, the price may include a locational premium and adjustments for heat content, premia to Pertamina[5], quality differentials and freight. In addition, the contracts provide for quantities and delivery of fuel that are more than sufficient to cover HECO's needs. Hence, HECO and HECO's customers are hedged with respect to availability and delivery of the physical commodities. HECO's fuel costs are variable as the price it pays will vary with the daily assessments for the assessments in HECO's fuel contracts.

With respect to price, despite the fact that the price varies with assessment values, HECO is hedged from the perspective of the utility. HECO's physical fuel supply contracts are struck at floating assessments. Similarly, its electricity rates float in accordance with the prices of oil that HECO pays. As my colleague Dr. Jeff Makholm explains, this is a logical regulatory framework, since HECO has no control over world oil prices. The matching of variable fuel operating expenses with variable electricity revenues helps to assure the financial integrity of the utility, while providing the economically-correct price signal to customers.

[5] The premia represent market premiums (or discounts) achieved in the spot market relative to a price assessment called the Pertamina Price Formula for LSWR.

Q. If HECO is hedged with respect to price, what is the relevance of the fuel hedging contracts cited in the Act?

A. The fuel hedging contracts referred to by the Act, if reasonably available, would only be entered into by HECO to meet the objective of mitigating oil price fluctuations for customers. Customers are exposed to fluctuations in world oil prices, while hedged against availability and physical delivery risks and costs. If HECO were to hedge, it would be to reduce this exposure. Of course, there would be a cost to reducing the exposure that may not be justified by the benefit.

SECTION 4: HEDGING ALTERNATIVES

Q. What strategies are available to buyers of commodities wishing to reduce exposure to short-term price fluctuations?

A. Buyers of commodities can use a number of different hedging strategies to manage short-term price risk. There are three strategies that are commonly used by buyers of commodities, which I explain in turn below:

1. Forward or futures contracts
2. Call option contracts
3. Collars (which are portfolios containing call option contracts and put option contracts[6])

I will address each in turn.

Q. What is a forward contract?

A. A forward contract is an agreement between two parties to buy or sell an asset or commodity at a pre-agreed future point in time. A standardized forward contract that is traded on an exchange is called a futures contract.

[6] A put option gives the owner the right, but not the obligation, to sell a commodity at specified price. Thus, a seller can use a put to determine a minimum price he will obtain on his sale.

Q. How are forward contracts used to hedge price risk?

A. Forward contracts are in most cases struck at fixed prices. A fixed-price forward contract locks in the price of the underlying commodity for both the buyer and seller. HECO-2203 illustrates the effect of a forward contract purchase for a buyer who, like HECO, would otherwise be purchasing the commodity on the open market at prevailing spot prices. This exhibit is illustrative of the impacts that purchasing forward can have on the price paid. However, this exhibit does not consider basis risks.

Q. What are basis risks?

A. Basis risks are the price risks that a buyer would be exposed to if the buyer cannot find a forward contract for the specific commodity it needs at the delivery location it needs. If the marketplace does not offer forward contracts that exactly match the commodity and the location where the buyer takes delivery, the buyer may purchase derivatives for a different commodity whose price is highly correlated with the product the buyer wishes to hedge. In addition, the buyer could purchase the same commodity it needs but at a delivery location other than the one where it takes delivery. In these cases, the buyer faces the risk associated with difference in prices between the two commodities or the two locations. These price differences are termed basis risk.

Even firms engaged in sophisticated hedging programs, such as Southwest Airlines, have run into problems with respect to basis risk. While I am not an accountant, it is my understanding that Statement of Financial Accounting Standards No. 133 (FASB 133) has strict provisions regarding basis risk, requiring that ineffective portions of hedges do not qualify for special hedge accounting treatment. Southwest Airlines' hedging program aims to hedge the price of jet fuel, an underlying commodity that is not traded on an organized futures exchange. Southwest Airlines explains that "ineffective" hedges are inherent to "hedging jet fuel with derivative positions based in other crude oil related commodities" and goes on to explain that ineffectiveness "may result, and has resulted, in increased volatility in the Company's results."[7] Thus, it is clear that basis risk is a significant issue, and may, in fact, preempt HECO from pursuing a financial hedging program that involves "ineffective" hedges. Customers may not be well served by hedges that involve basis risk.

As I explain further below, forward contracts are not readily available for the oil products and delivery locations that HECO needs, which means that if HECO decides to hedge, it will be exposed to considerable basis risk.

Q. What is a fixed-for-floating swap?

A. A fixed-for-floating swap is a contract between two parties under which one party agrees to swap a fixed price for a published index price on a notional quantity. A fixed-for-floating swap is economically equivalent to a fixed-price forward contract. The difference is that the fixed-for-floating swap is a purely financial instrument, while a forward contract generally anticipates physical delivery.

Q. What is a call option and how could it be used to mitigate price risk?

A. A call option gives its owner the right, but not the obligation, to buy an asset or commodity on a specified date (the expiration date), for a specified price (the strike price). HECO-2204 illustrates the payouts that would accrue to the purchaser of a call option. Call options cap the price that will be paid by a buyer for a commodity. Again, this exhibit does not capture basis risks.

Q. What is a collar and how does it limit risk?

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[7] Southwest Airlines Co., 10-Q, October 20, 2006, p. 10.

A. A collar is a portfolio of options that are used to assure that the price of a commodity is within a given range. A buyer of a commodity who wishes to put a cap and floor on the price paid would sell a put option and buy a call option. This strategy assures that the price of the commodity will be within a given range – i.e., no lower than the strike price of the put (the floor) and no higher than the strike price of the call (the cap). HECO-2205 illustrates the payouts that would accrue to the purchaser of a collar ignoring basis risks.

SECTION 5: REALITIES OF THE MARKETPLACE

Q. Please describe any practical obstacles or constraints that HECO would face if it were to enter the marketplace seeking to hedge on behalf of customers, that is, if it were seeking to limit the impact of fluctuations in world oil prices on customer rates.

A. I identify five important constraints that HECO would face.

1. The first important constraint relates to the duration of the hedge. As I mentioned, the liquid forward and futures contracts that are traded in the marketplace do not extend beyond a term of 18 months. Further, the most liquid (*i.e.*, readily-available to trade) fuel hedging contracts are contracts that cover time periods of up to six months into the future. This is illustrated in HECO-2201.
2. The second constraint faced by HECO is that hedging contracts for the precise oil products and delivery points that HECO would need are not visible in the marketplace. HECO would therefore be exposed to considerable basis risks if it used the oil derivatives that are readily-available in the marketplace. It is possible that HECO could obtain a customized swap agreement that hedges the

price of the specific oil products in the specific locations that from the basis for the pricing formulas in HECO's physical oil contracts. However, such a swap would be less transparent and it can be expected to be more expensive because the seller of such a swap would need to be remunerated for absorbing the basis risks and illiquidity of offering such a hedge. To illustrate the potential size of basis risks, I have shown the daily basis differential of the oil products that HECO and its affiliates use relative to spot prices of oil products for which HECO could obtain liquid hedges. These daily basis differentials are shown in HECO-2206. Note that the price of the product which drives HECO's costs is not exactly equal to the price of the product that would be hedged. This difference is basis risk. HECO may hedge Brent futures, but if Brent futures rise by $15 per barrel and the Singapore low sulfur waxy reserve ("LSWR") assessment in HECO's LSFO contracts rises by $20 per barrel, HECO would not be hedged to the full extent. Similarly, if Brent futures rise $25 per barrel and the Singapore LSWR assessment in HECO's contracts rises by $20 per barrel, the Brent hedge would overcompensate for the rise in the price of the LSWR assessment.

In addition, there is an issue of the incongruence of pricing dates relevant to the hedging commodity and the short commodity. Whereas HECO's contracts for fuel are based on lagged thirty-day average prices, cash flows from hedging would be based on two days, the day on which the hedge is purchased and the settlement date (the last trading day before delivery). Thus, while the settlement date of a hedge will reflect price movements up to the day before delivery, the price of the short commodity will reflect markets 10 to 40 days earlier. Changes in the market during the forty-day period before the settlement date will affect the basis and cause the hedge to be less effective. HECO-2207 illustrates the magnitude of these basis changes. If the basis between the short commodity (the fuel burned by HECO) and the hedge commodity (the futures used to hedge the short commodity) were constant, the ratio of the change in the hedge commodity to the change in the short commodity would be 1:1 = 100%. Instead, a historical "what if" analysis of fuel hedges shows that this ratio, or the effectiveness of the hedge, deviates greatly. For example, in 2003, yearly heating oil hedges moved 35.54 times in the *opposite* direction of the short commodity on an average basis. Thus, hedging strategies using these futures cannot be counted on to provide a reliable offset to movements in the price of the fuels burned by HECO.

If HECO were to look for alternatives, it would most likely be limited to customized products in the over-the-counter market. However, as mentioned above, prices for such products would most likely be less transparent and more expensive, which would increase costs and risks for customers.

3. The third constraint faced by HECO is the quantity which it would hedge. The quantities that HECO needs of each type of fuel fluctuate month to month and year to year in accordance with changing demand, availability and relative economics of generation plants, among other factors. HECO's existing fuel contracts provide for flexibility on the quantities taken, subject to a minimum and maximum take. The quantity flexibility embedded in HECO's existing fuel contracts would be difficult to match in the financial derivatives markets, which offer fixed quantity products. If HECO were to hedge the minimum expected quantity, HECO's customers would face market risk exposure for incremental quantities, while hedging the maximum expected quantity would

result in market risk exposure for decremental quantities. This quantity risk is important and makes hedging difficult. I have illustrated the variable quantities needed for each type of oil used by HECO and its affiliates in HECO-2208.

4. Fourth, if HECO decides to engage in hedging, HECO may face credit risk Credit risk is the risk of a financial loss associated with the failure of a party to perform on its obligations under a hedging contract. Credit risk is an important factor when considering fuel hedging contracts. Market practice is to mark forward contracts to market and to collateralize the credit exposure embedded in forward contracts. This means that the value of the contract is calculated every day and any exposure must be covered as margin. If HECO engages in hedging, counterparties may require that HECO provide collateral. The provision of collateral would add to the cost of hedging. Further, HECO would in most instances be exposed to the risk of counterparty default and non-performance.

5. Fifth, the execution of fuel hedging contracts would expose HECO to liquidity risks. Liquidity is the ability to execute transactions in the marketplace. Markets that are highly liquid have active trading and many buyers and sellers. Market liquidity for oil derivatives ebbs and flows. When the markets are less liquid, buyers and sellers may face difficulties entering into or exiting positions. Markets with low liquidity may inhibit HECO's ability to execute or unwind hedge positions. In addition, low liquidity would harm HECO's ability to replace a position as a result of counterparty default. Low liquidity also impedes the ability of a buyer to obtain a favorable price. The risk that these markets would not be liquid is a real one and could present significant

price penalties and transaction constraints. Liquidity and its effect on price and the ease of making transactions should be fully understood and examined prior to HECO's embarking on a hedging program.

Q. Have you prepared a summary of the costs and risks for HECO and its customers of entering into fuel hedging contracts?

A. Yes. This is shown in HECO-2202. An analysis of whether the hedging alternatives that are available in the exchange and OTC markets are reasonable for HECO to enter into must consider the risks shown in that exhibit, which include:

- Administrative costs,
- Market risk including quantity risk (i.e., hedge quantity as compared to Hawaiian Electric's needs) and basis risk,
- Credit risk,
- Liquidity risk, and
- Duration of the hedge.

These factors indicate that HECO's fuel costs will continue to fluctuate even if hedges are entered into due to risks that cannot be hedged. They also indicate that hedging will introduce new costs for customers that are not borne under the current regulatory regime.

Q. In considering these factors for HECO, what are the most significant barriers to HECO hedging oil to achieve a stable price?

A. Were HECO to hedge using the most liquid products, it would face considerable basis risks. That is, the liquid, transparent and readily available hedges pose basis risk and would have limited hedge effectiveness. Again basis risk arises from the fact the change in prices of the hedge differs from the change in price of the actual physical commodity that HECO purchases. Were HECO to hedge using products with less basis risk, these products would be less liquid and less transparent. This is especially problematic for a regulated firm that must be able to demonstrate the reasonableness of its purchases. Neither buying less effective hedges nor buying less liquid and less transparent hedges is desirable as there are more effective means of achieving the same objective.

Q. Does this conclude your testimony?

A. Yes.

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Mr. Eugene Meehan is a Senior Vice President with NERA. He has over twenty-five years of experience consulting with electric and gas utilities. Mr. Meehan has testified as an expert witness before numerous state and federal regulatory agencies and appeared in federal court and arbitration proceedings.

His practice concentrates on serving NERA's energy industry clients, with a focus on helping clients manage the transition from the regulatory to a more competitive environment. Mr. Meehan has performed consulting assignments for over fifty large electric, gas, and combination utilities in the areas of retail access, regulatory strategy, strategic planning, financial and economic analysis, merger and acquisition advisory services, power contract analysis, market power and market definition, stranded cost analysis, power pooling, power markets and risk management, ISO and PX development, and costing and pricing. Mr. Meehan has advised numerous utilities on power procurement issues and administered power procurements on behalf of utilities and regulators.

Mr. Meehan has led NERA's advisory work on several major restructuring and unbundling assignments. These assignments were multi-year projects that involved integration of regulatory strategy, business strategy and development of regulatory filings associated with the recovery of stranded cost and rate unbundling.

Eugene T. Meehan
National Economic Research Associates, Inc.

Education

Boston College, BA, Economics, cum laude
New York University (NYU), Graduate School of Business, completed core courses for the doctoral program.

Professional Experience

	National Economic Research Associates
1999-Present	Senior Vice President
	National Economic Research Associates
1996-1999	Vice President
	Deloitte & Touche Consulting Group
1994-1996	Principal
	Energy Management Associates, Inc.
1980-1994	Vice President
	National Economic Research Associates, Inc.
1973-1980	Senior Economic Analyst, Research Assistant

Areas of Expertise

Restructuring/Stranded Cost Recovery: Mr. Meehan directed several multi-year projects associated with restructuring and stranded cost recovery. These projects involved facilitating the development of an integrated regulatory and business strategy and formulation of regulatory filings to accomplish strategy. These assignments required facilitating sessions with senior management to set and track filing strategy. Clients included Public Service Gas & Electric and Baltimore Gas and Electric.

Unbundling/Generation Pricing: Mr. Meehan has formulated unbundling strategies, specializing in generation pricing. He has advised several utilities in standard offer pricing and testified on shopping credits on behalf of First Energy and Baltimore Gas and Electric.

Power Procurement: Mr. Meehan has been involved in power procurement activities for a variety of utilities and regulatory agencies. He has advised utilities in developing and implementing evaluation processes for new generation that had the objective of achieving the best portfolio evaluation. He has helped regulators in Ireland and Canada design and implement portfolio evaluation processes. He has testified before the FERC and state regulatory agencies on competitive power procurement. Additionally Mr. Meehan helped design and implement the New Jersey BGS auction process.

Power Contracts: Mr. Meehan has extensive experience with power contracts and power contract issues. He has reviewed in detail and testified on the three principal types of power contracts. These are integrated utility to integrated utility contracts, IPP to utility contract and integrated or wholesale utility to distribution utility contracts. He has testified in such contracts disputes on behalf of Carolina Power and

Light, Duke Power Company, Southern Company, Orange and Rockland Utilities and Tucson Electric Power. Amounts in dispute in these cases have ranged to $1 billion. He has also advised Oglethorpe Power Corporation in the reform of its wholesale contracts with its distributor cooperative members.

Retail and Wholesale Settlements: In addition to his expertise on power pooling issues, Mr. Meehan has recently devoted substantial efforts to assignments related to the settlement process. He has focused on the issues of credit management as new entrants appear in retail and wholesale markets, designing efficient specifications for retail settlement systems including the use of load profiling, and examining the risk and cost allocation issues of alternative settlement systems.

Risk Management: Mr. Meehan has advised several large utilities in the area of price risk management. These assignments have included evaluation of price management service offers solicited from power marketers in association with management of assets and entitlements and provision of price managed service for various terms.

Marginal Costs: Mr. Meehan has been responsible for comprehensive marginal cost analysis for over twenty-five North American Utilities. These assignments required detailed knowledge of utility operations and planning.

Power Supply and Transmission Planning: Mr. Meehan has advised electric utilities on economic evaluations of generation and transmission expansion. He has testified on the economics of particular investments, the prudence of planning processes and the prudence of particular investment decisions.

Generation Strategy: Mr. Meehan has led NERA efforts on a client task force charged with developing an integrated generation asset/power marketing strategy.

Power Pooling: Mr. Meehan has an in-depth working knowledge of the operating, accounting and settlement processes of all United States power pools and representative international power pools. He has provided consulting services for New York Power Pool members on a continuous basis since 1980, advising the Pool and its members on production cost modeling, transmission expansion, competitive bidding and reliability and marginal generating capacity cost quantification. In NEPOOL he has quantified the benefits of continued utility membership in the Pool and the impact of the Pool settlement process on marginal cost. He has worked with a major PJM utility to examine the impact of PJM restructuring proposals upon generating asset valuation and to examine the implications of alternative restructuring proposals. He has consulted for Central and Southwest Corporation, Entergy and Southern Company on issues that involved the internal pooling arrangements of the utility operating companies of those holding companies and for various utilities on the impact of pooling arrangements on strategic alternatives. There is probably no other individual who is as familiar with as many pools and the variety of issues that these pools have encountered over the years.

Representative Assignments

Representative assignments, which Mr. Meehan directed for energy clients, include the following:

- Working with Public Service Electric & Gas Company (PSE&G), Mr. Meehan directed a three year NERA advisory effort on restructuring. Mr. Meehan facilitated a two day senior management meeting to set regulatory strategy in 1997. Throughout 1997 and 1998 Mr. Meehan worked over half time at PSE&G to help implement that strategy and advised on testimony preparation, cross-examination and briefing. He also advised PSE&G on business issues related to securitization, energy settlement and credit requirements for third party suppliers. During 1999 Mr. Meehan advised PSE&G during settlement negotiations and litigation of the settlement. PSE&G achieved a restructuring outcome that involved continued ownership of generation by an affiliate and the securitization of $2.5 billion in stranded costs.

- Working on separate assignments for a large utility in the Northeast and a large utility in the Southeast, Mr. Meehan advised on the evaluation of risk management offers from power marketers. The assignments included review of proposals, attendance of interviews with marketers and advice on these and the development of analytical software to evaluate offers.

- Working with government of Ontario beginning in 2004, Mr. Meehan helped design the RFP and economic evaluation process for the solicitation of 2500 Mw of new generating capacity. NERA, under Mr. Meehan's supervision will conduct the portfolio based economic evaluation on behalf of the Ontario Ministry of Energy.

- Mr. Meehan testified on behalf of Pacific Gas & Electric Company before the FERC in a case benchmarking the PSA between the distribution utility and a to be created generating company. This effort involved developing detailed expertise in applying the Edgar standard and a detailed review of DWR procurement during the western power crisis. Additionally this effort involved the review of over 100 power contracts in the WECC.

- Mr. Meehan directed NERA's efforts for the electricity regulator in Ireland to design and RFP and implementation process fro the purchase of 500 Mw of new generating capacity. NERA advised on the RFP, the portfolio evaluation method and the power contract. Further NERA conducted the economic evaluation. This work was in 2003.

- Mr. Meehan reviewed the economic evaluation conducted by Southern Company Service for affiliated operating companies in connection with an RFP for over 2000 Mw of new generating capacity. Mr. Meehan submitted testimony before the FERC on behalf of Southern.

- Working with Baltimore Gas and Electric (BG&E) Mr. Meehan conducted a one and one-half year consulting effort advising on restructuring. Mr. Meehan began the project in March and April 1998, leading senior management discussions and workshops on plan development and filing strategy. He advised BG&E in the development of testimony, rebuttal testimony and public information dissemination. Mr. Meehan worked to review and coordinate testimony from all witnesses and offered testimony on shopping credits. He also offered testimony in defense of the case settlement. BG&E achieved a restructuring outcome enabling it to retain generation ownership. As part of this assignment, Mr. Meehan advised BG&E on generation valuation and unregulated generation business strategy.

- Mr. Meehan has directed the efforts of a large Southeastern utility to develop a short-term power contract portfolio and to evaluate the relative value of power options, forwards and unit contracts to determine the optimal mix of instruments to manage price risk.

Eugene T. Meehan

National Economic Research Associates, Inc.

- Mr. Meehan recently testified for XCEL Energy on the use of competitive bids for new generation needs. The issue addressed by Mr. Meehan involved an examination of whether the Company was prudent not to explore a self-build plan and the reasonableness of relying on ten-year or shorter contracts as opposed to life of facility contracts in order to meet needs and facilitate a possible future transition to competition. This project addressed the comparability of fixed bids to rate base plant additions.

- Mr. Meehan advised and testified on behalf of First Energy in the Ohio restructuring proceeding on the issues of generation unbundling and stranded cost. He defended the First Energy shopping credit proposal.

- Mr. Meehan advised Consolidated Edison and Northeast Utilities on merger issues and testified in Connecticut and New Hampshire merger proceedings. The subject of his testimony was retail competition in gas and electric commodity markets.

- Mr. Meehan directed NERA's effort to train selected representatives of a major European power company in the United States power marketing and risk management practices. The project involved numerous visits and interviews with power marketing firms.

- Mr. Meehan has led NERA effort to advise the New England ISO on the development of an RTO filing. This work has involved an examination of performance-based ratemaking for transmission and market operator functions.

- Mr. Meehan examined ERCOT power market conditions during the 1997 to 1999 period and testified on behalf of Texas New Mexico Power Company for the prudence of its power purchase activity.

- Mr. Meehan has advised a Midwestern utility on restructuring of a wholesale contract with an affiliate. The issues involve forecasting of the unbundled wholesale cost of service and forecasts of market prices as well as development of a regulatory strategy for gaining approval of contract restructuring and the transferring of generation from regulated to EWG states.

- Mr. Meehan has performed market price forecasts for numerous utility clients. These forecasts have employed both traditional modeling and newly developed statistical approaches.

- Examined the credit issues associated with the entry of new entities into retail and wholesale settlement market. These assignments involved a review of current Pool credit procedures, examination of commodity and security trading credit requirements, coordination with financial institutions and recommendations concerning credit exposure monitoring, credit evaluation processes and credit requirements.

- Oversight of EMA's consulting and software team in designing and implementing the LOLP capacity payment, portion of the U.K. wholesale settlement system.

Eugene T. Meehan

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- Advised Oglethorpe Power Corporation in the reform of its contracts with its distribution cooperative members, and the evolution of full requirement power wholesale power contracts into contracts that preserved Oglethorpe's financial integrity and were suitable for a competitive environment.

- Development of long run marginal and avoided costs of natural gas service and avoided cost methods and procedures. These costs have been used primarily for the analysis of gas DSM opportunities. Clients include Consolidated Edison Company, Southern California Edison Company, Niagara Mohawk Power Corporation, and Elizabethtown Gas Company.

- Review of power contracts and testimony in numerous power contract disputes.

- Development of long run avoided costs of electricity service and avoided cost methods and procedures. These costs have been used to assess DSM, cogeneration, and in the development of integrated resource plans. Clients include Public Service Company of Oklahoma, Central Maine Power Company, Duquesne Light Company, and the New York investor-owned utilities.

- Advised Central Maine Power Company (CMP) on the development of a competitive bidding framework. This framework was implemented in 1984 and was the first such in the nation. CMP adopted the framework outlined in EMA's report and won prompt regulatory approval.

- Advised a utility in the development of an incentive ratemaking plan for a new nuclear facility. This assignment involved strategic analysis of alternate proposals and quantification of the financial impact of various ratemaking alternatives. Presentation of strategic and financial results helped convince senior management to initiate negotiations for the incentive plan.

- Advised and testified on behalf of the New York Power Pool utilities on the methodology for measuring pool marginal capacity costs. This work included development of the methodology and implementation of the system for quantifying LOLP based marginal capacity costs.

- Provided testimony on behalf of the investor-owned electric utilities in New York state concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs. This methodology was adopted by the Commission and used as the basis for DSM evaluation in New York from 1982 through 1988.

- Developed the functional design of a retail access settlement system and business processes for a major PJM combination utility. This design is being used to construct a software system and develop business procedures that will be used for retail settlements beginning January 1999.

- Reviewed the power pool operating and interchange accounting procedure of the New York Power Pool, the Pennsylvania, New Jersey, Maryland Interconnection, Allegheny Power System, Southern Company, and the New England Power Pool for various consulting assignments and in connection with the development of production simulation software.

Eugene T. Meehan

National Economic Research Associates, Inc.

- Summarized and analyzed the operational NEPOOL to examine the feasibility of incorporating NEPOOL interchange impacts with Central Maine and accounting procedure of the New England Power Pool Power Company's buy-back tariffs.

- Developed and presented a two-day seminar delivered to electric industry participants in the United Kingdom, prior to privatization, outlining the structure and operation of power pools and bulk power market transactions in North America.

- Benchmark analysis and FERC testimony of PGE's proposed twelve year contract between PG&E and Electric Gen LLC including contract value in excess of $15 billion.

- Responsible for NERA's overall efforts with respect to advising New Jersey's Electric Distribution Companies on the structuring and conduct of the Basic Generation Service auctions. The 2002 auction was over $3.5 billion and the 2003 and 2004 auction were for over $4.0 billion.

Expert Testimony

Mr. Meehan has provided expert testimony in the following forums:

- Arkansas Public Service Commission
- Federal Energy Regulatory Commission
- Florida Public Service Commission
- Maine Public Utilities Commission
- Minnesota Public Service Commission
- Nevada Public Service Commission
- New York Public Service Commission
- Nuclear Regulatory Commission – Atomic Safety and Licensing Board
- Oklahoma Public Service Commission
- Public Service Commission of Indiana
- Public Utilities Commission of Ohio
- Public Utilities Commission of Nevada
- Public Utilities Commission of Texas
- Public Utilities Commission of New Hampshire
- Colorado Public Utilities Commission
- United States District Court
- United States Senate Committee on Energy and Natural Resources

Eugene T. Meehan
National Economic Research Associates, Inc.

- Various arbitration proceedings

Clients on whose behalf Mr. Meehan has testified include

- Arkansas Power & Light Company
- Baltimore Gas & Electric
- Carolina Power & Light Company
- Central Maine Power
- Consolidated Edison Company of New York, Inc.
- Dayton Power and Light Company
- Florida Coordinating Group
- Houston Lighting & Power Company
- Minnesota Power and Light Company
- Nevada Power Company
- Niagara Mohawk Power Corporation
- Northern Indiana Public Service Company
- Oglethorpe Power Corporation
- Pacific Gas and Electric Company
- Power Authority of the State of New York
- Public Service and Electric Company
- Public Service Company of Oklahoma
- Sierra Pacific Power Company
- Southern Company Services, Inc.
- Tucson Electric Power Company
- Texas-New Mexico Power Company

Specific List of Recent Expert Testimonies and Expert Reports

- Supplemental Testimony on behalf of Texas-New Mexico Power Company, Docket No. 15660, September 5, 1996

Eugene T. Meehan

National Economic Research Associates, Inc.

- Direct Testimony on behalf of Long Island Lighting Company before the Federal Energy Regulatory Commission, September 29, 1997
- Rebuttal Testimony on behalf of Texas-New Mexico Power Company, SOAH Docket No. 473-97-1561, PUC Docket No. 17751, March 2, 1998
- Prepared Testimony and deposition testimony on behalf of Central Maine Power Company, United Stated District Court Southern District of New York, 98-civ-8162 (JSM), March 5, 1999
- Prepared Direct Testimony Before the Public Service Commission of Maryland on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, June 1999
- Rebuttal Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, March 22, 1999
- NORCON Power Partners LP v. Niagara Mohawk Energy Marketing, before the United States District Court, Southern District of New York, June 1999.
- Prepared Supplemental Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, July 23, 1999
- Prepared Supplemental Reply Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, August 3, 1999
- Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0681, September 3, 1999
- Rebuttal Testimony on behalf of Niagara Mohawk, PSC Case No. 99-E-0681 Before the New York State Public Service Commission, November 10, 1999
- Arbitration deposition on behalf of Oglethorpe Power Corporation, last quarter of 1999
- Direct Testimony Before the Public Utilities Commission of Ohio on behalf of FirstEnergy Corporation, Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company, Case No. 99-1212-EL-ETP re: Shopping Credits
- Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0990, February 25, 2000
- Testimony on behalf of Consolidated Edison Company of New York, Inc., State of Connecticut, Department of Public Utility Control, Docket No.: 00-01-11, April 28, 2000 and June 30, 2000
- Testimony on behalf of Texas-New Mexico Power Company, Fuel Reconciliation Proceeding before the Texas PUC, June 30, 2000
- Testimony on behalf of Consolidated Edison Company of New York, Inc., Before the New Hampshire Public Service Commission, Docket No.: DE 00-009, June 30, 2000
- Rebuttal Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, November 22, 2000
- Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, January 19, 2001

Eugene T. Meehan

National Economic Research Associates, Inc.

- DETM Management, Inc. Duke Energy Services Canada Ltd., And DTMSI Management Ltd., Claimants vs. Mobil Natural Gas Inc., And Mobil Canada Products, Ltd., Respondents. American Arbitration Association Cause No. 50 T 198 00485 00. August 27, 2001
- State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv) Docket No.: EX01050303, October 4, 2001
- Direct Testimony Before the Federal Energy Regulatory Commission on behalf of Pacific Gas and Electric Company, Docket No.: ER02-456-000, November 30, 2001
- Fourth Branch Associates/Mechanicville Vs. Niagara Mohawk Power Corporation, January 2002 (Expert Report).
- Arbitration Deposition on behalf of Oglethorpe Power Corporation, March 2002
- Direct Testimony and Deposition Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, July 16, 2002
- Rebuttal Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, August 13, 2002
- Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, in the matter of the Application of Nevada Power Company to Reduce Fuel and Purchased Power Rates, PUCN Docket No. 02-11021, November 8, 2002 and subsequent Deposition Testimony
- Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, Docket No. 03-1014, January 10, 2003
- Direct Testimony Before the Public Utility Commission Of Texas on behalf of Texas-New Mexico Power Company, Application Of Texas-New Mexico Power Company For Reconciliation Of Fuel Costs, April 1, 2003
- Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, PUCN Docket No. 02-11021, April 1, 2003
- Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company, Docket No. 03-1014, May 5, 2003
- Testimony on behalf of Consolidated Edison Company of New York, Inc., Before the Public Service Commission of New York, Case No.: 00-E-0612, September 19, 2003
- State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv) September 2003
- Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 12, 2003

Eugene T. Meehan

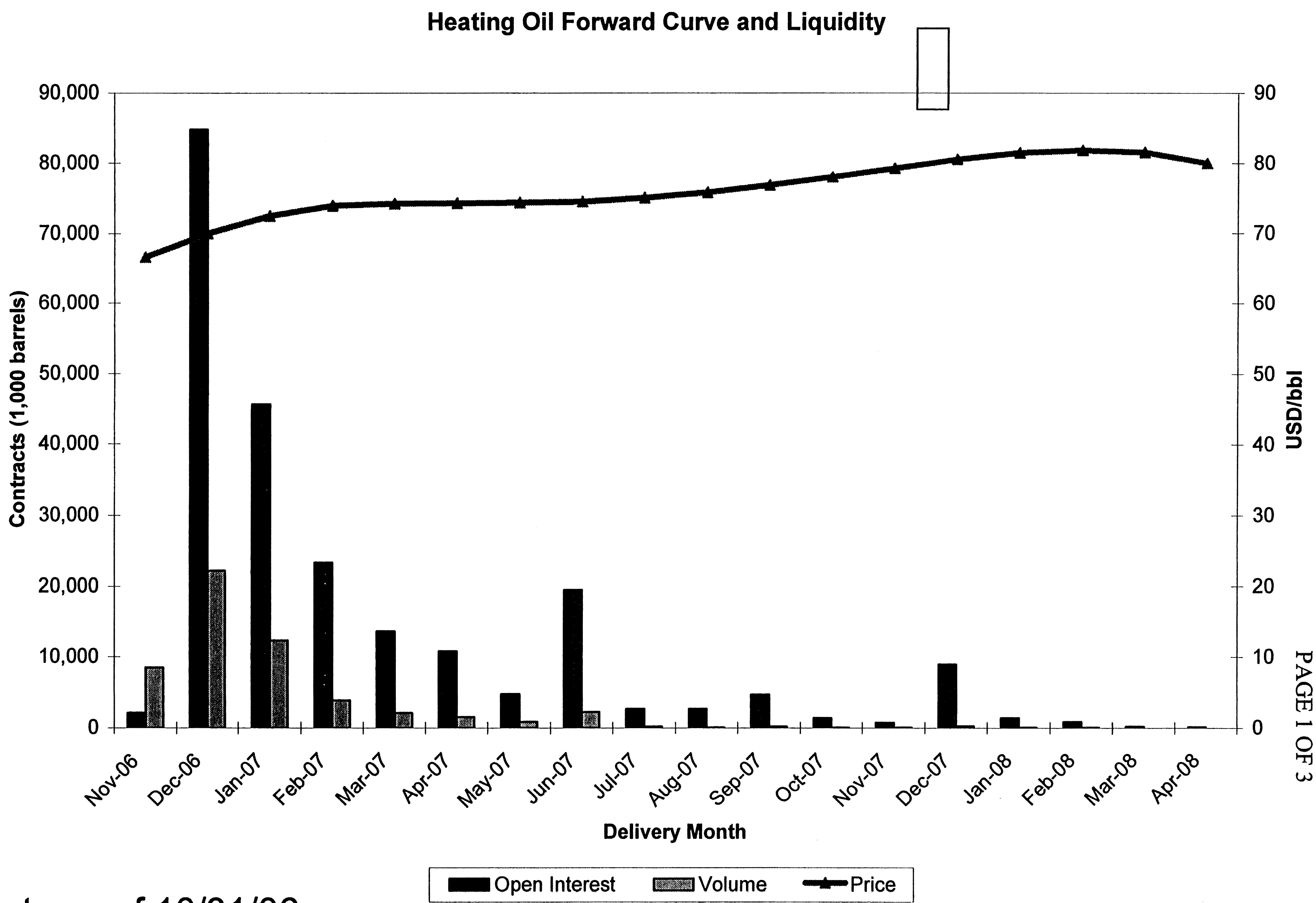
National Economic Research Associates, Inc.

- Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 12, 2004
- Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, May 28, 2004
- Direct Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, January 22, 2004
- Rebuttal Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, April, 2004
- State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv) September 2004
- Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 9, 2004
- Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 7, 2005
- Expert Report on behalf of Oglethorpe Power Corporation, March 23, 2005
- Arbitration deposition on behalf of Oglethorpe Power Corporation, April 1, 2005
- Remand Rebuttal Testimony for Public Service Company of Oklahoma, Cause No. PUD 200200038, March 17, 2006
- Answer Testimony on behalf of the Colorado Independent Energy Association, AES Corporation and LS Power Associates, L.P., Docket No. 05A-543E, April 18, 2006
- Cross-Answer Testimony on behalf of the Colorado Independent Energy Association, AES Corporation and LS Power Associates, L.P., Docket No. 05A-543E, May 22, 2006

May 2006

HECO-2201 LIQUIDITY CHARTS FOR 3 FUTURES HEDGES (1 of 3)

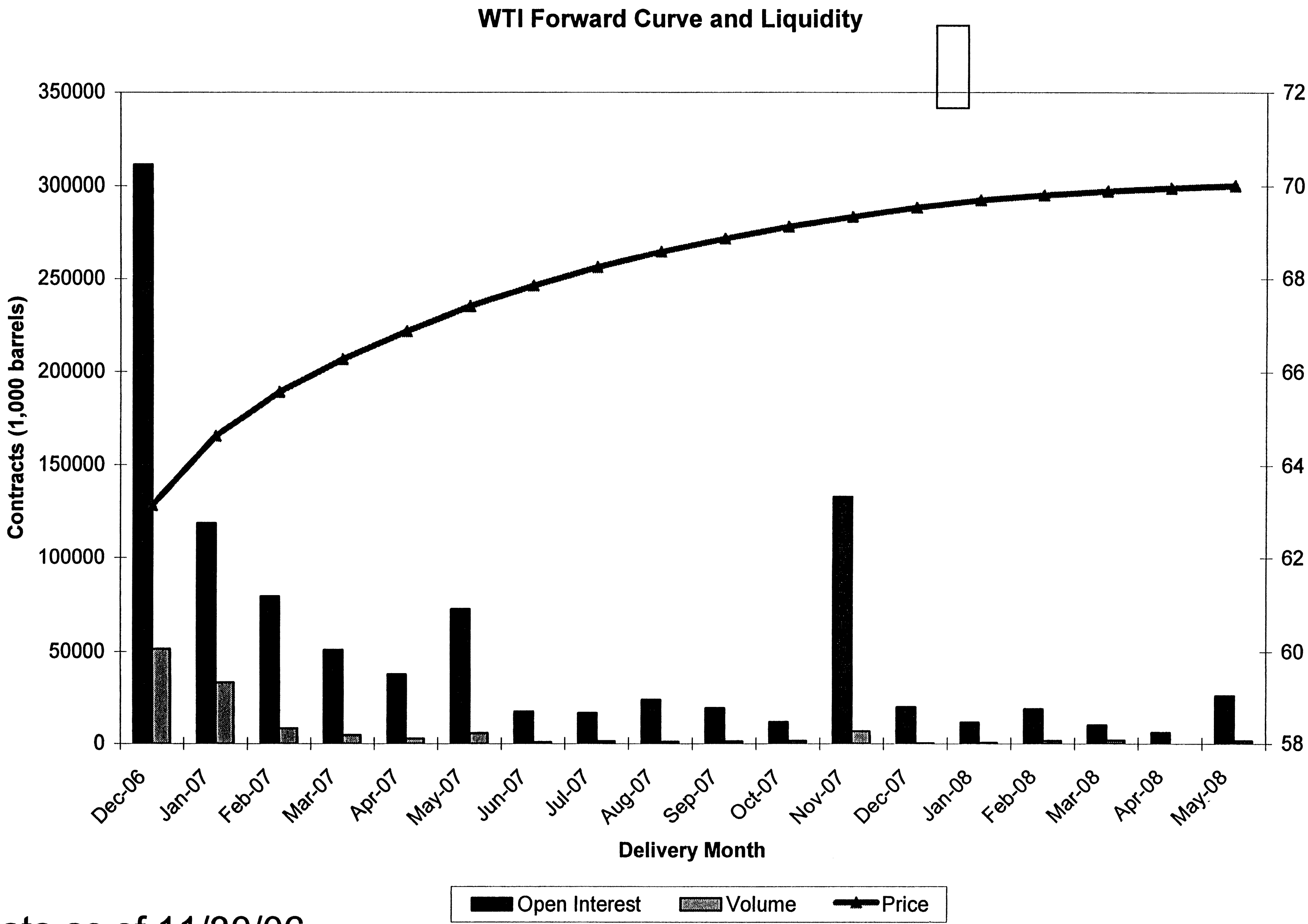
NERA Economic Consulting



Data as of 10/31/06

HECO-2201 LIQUIDITY CHARTS FOR 3 FUTURES HEDGES (2 of 3)

NERA Economic Consulting



Data as of 11/30/06

HECO-2201
DOCKET NO. 2006-0386
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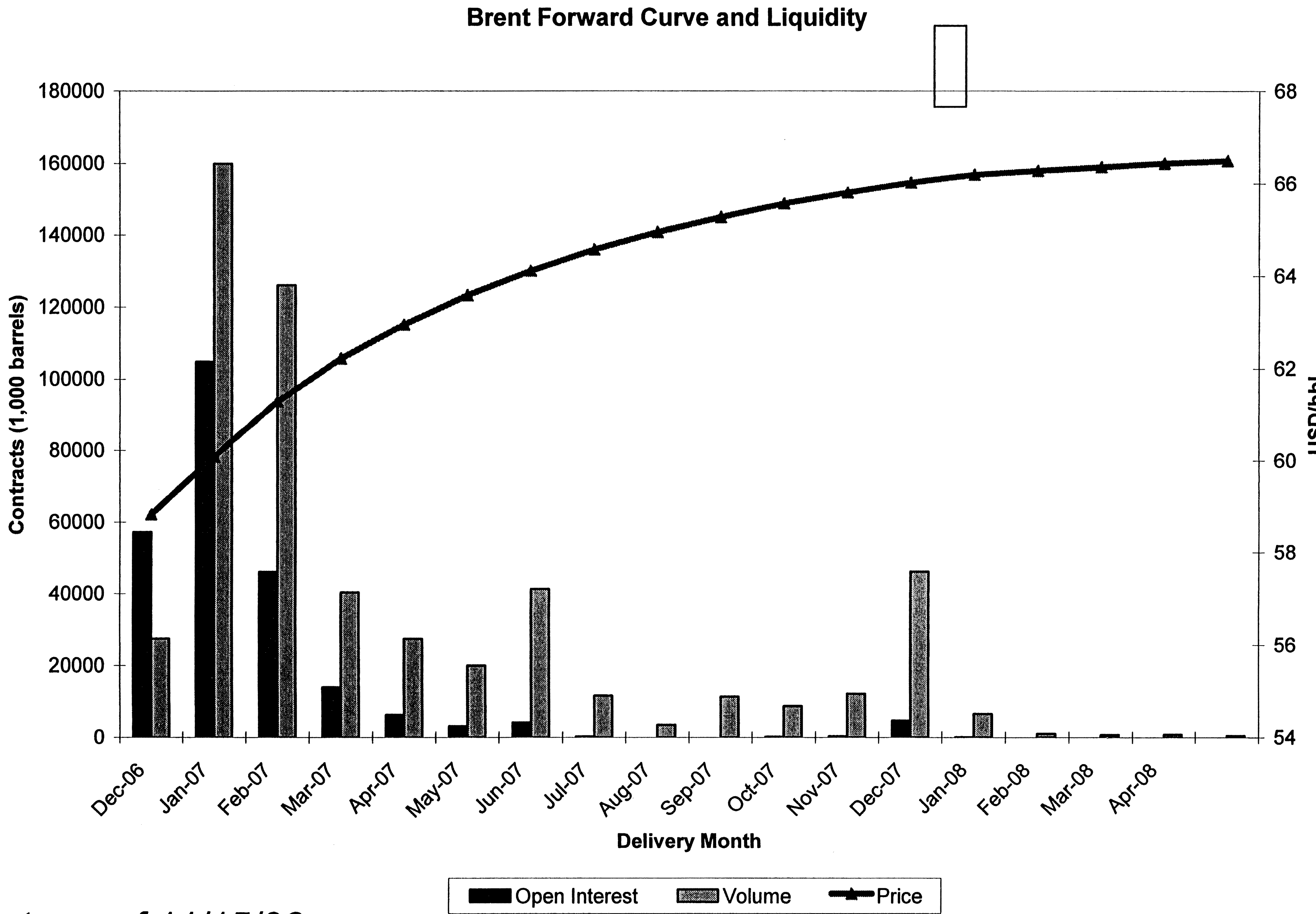
HECO-2201 LIQUIDITY CHARTS FOR 3 FUTURES HEDGES (3 of 3)

NERA Economic Consulting



Data as of 11/15/06

HECO-2202

COSTS AND RISKS OF HEDGING

NERA Economic Consulting

Cost	Administrative cost	Cost of collateral postings Compliance with hedge accounting rules. Up-front regulatory costs (cost of establishing hedging objective and hedging program including execution timeframe, contract types, contract duration) Ongoing regulatory costs (costs of obtaining periodic regulatory pass through of hedging costs)
Risk	Market risks	Market risks on incremental/decremental quantities Basis risk. Difference in prices of hedge commodity and short commodity spread widens or contracts, thus reducing the effectiveness of the hedge
Risk	Credit risks	Counterparty default risk
Risk	Liquidity risks	Ability to unwind or replace positions
Risk	Duration of hedge	Increases market, credit and liquidity risks

HECO-2202
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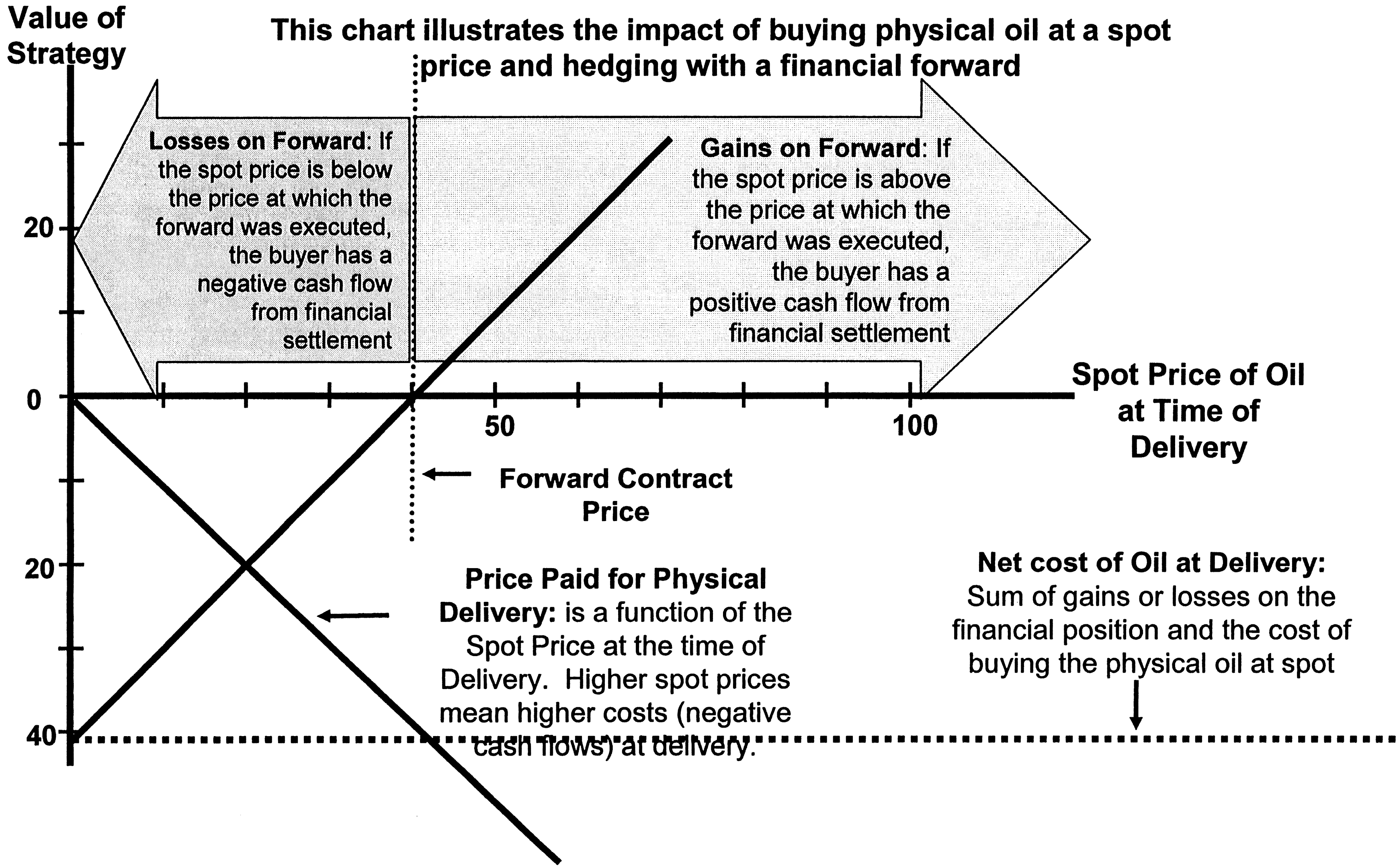
HECO-2203
Payout Diagram – Buyer Enters into Fixed-price Forward (no basis)

NERA Economic Consulting



A forward contract fixes the cost of the commodity for the buyer

HECO-2203
DOCKET NO. 2006-0386
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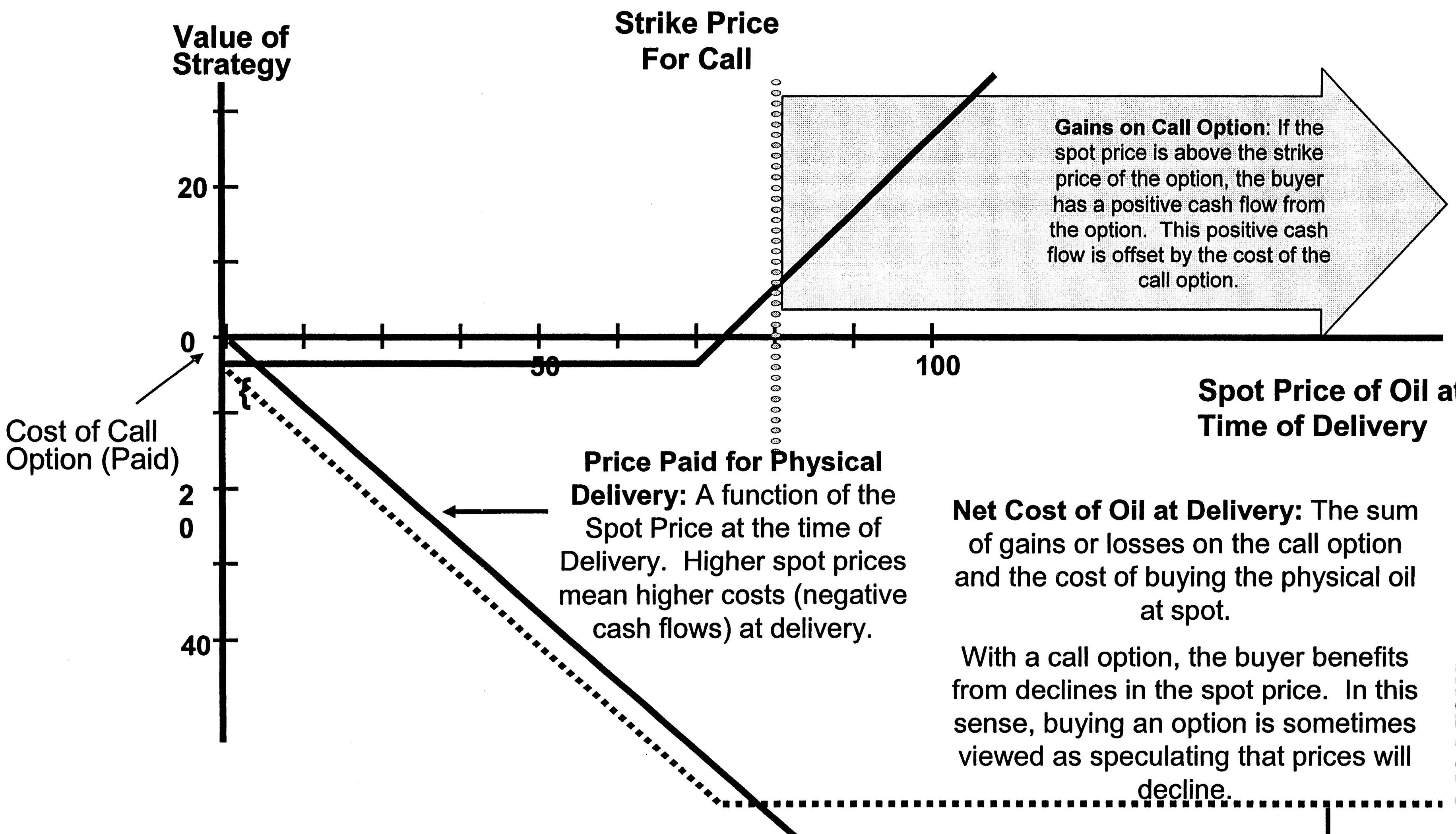
HECO-2204
Payout Diagram – Buyer Enters into Call Option Contract (no basis)

NERA Economic Consulting



A call option puts a cap on the cost of the commodity for the buyer

HECO-2204
DOCKET NO. 2006-0386
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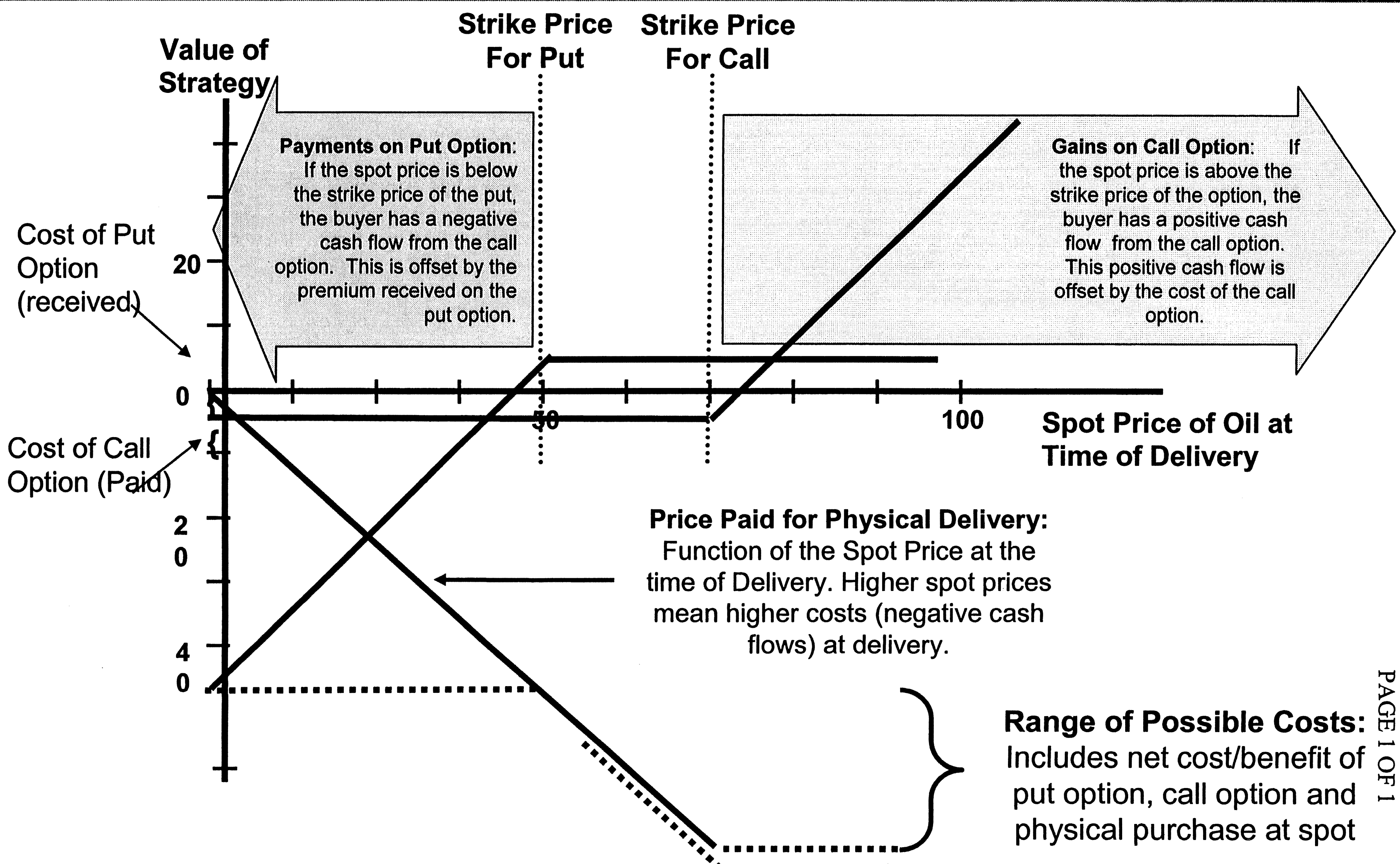
HECO-2205
Payout Diagram – Buyer Enters into Collar (no basis)

NERA Economic Consulting



A collar puts a cap and a floor on the cost of the commodity for the buyer

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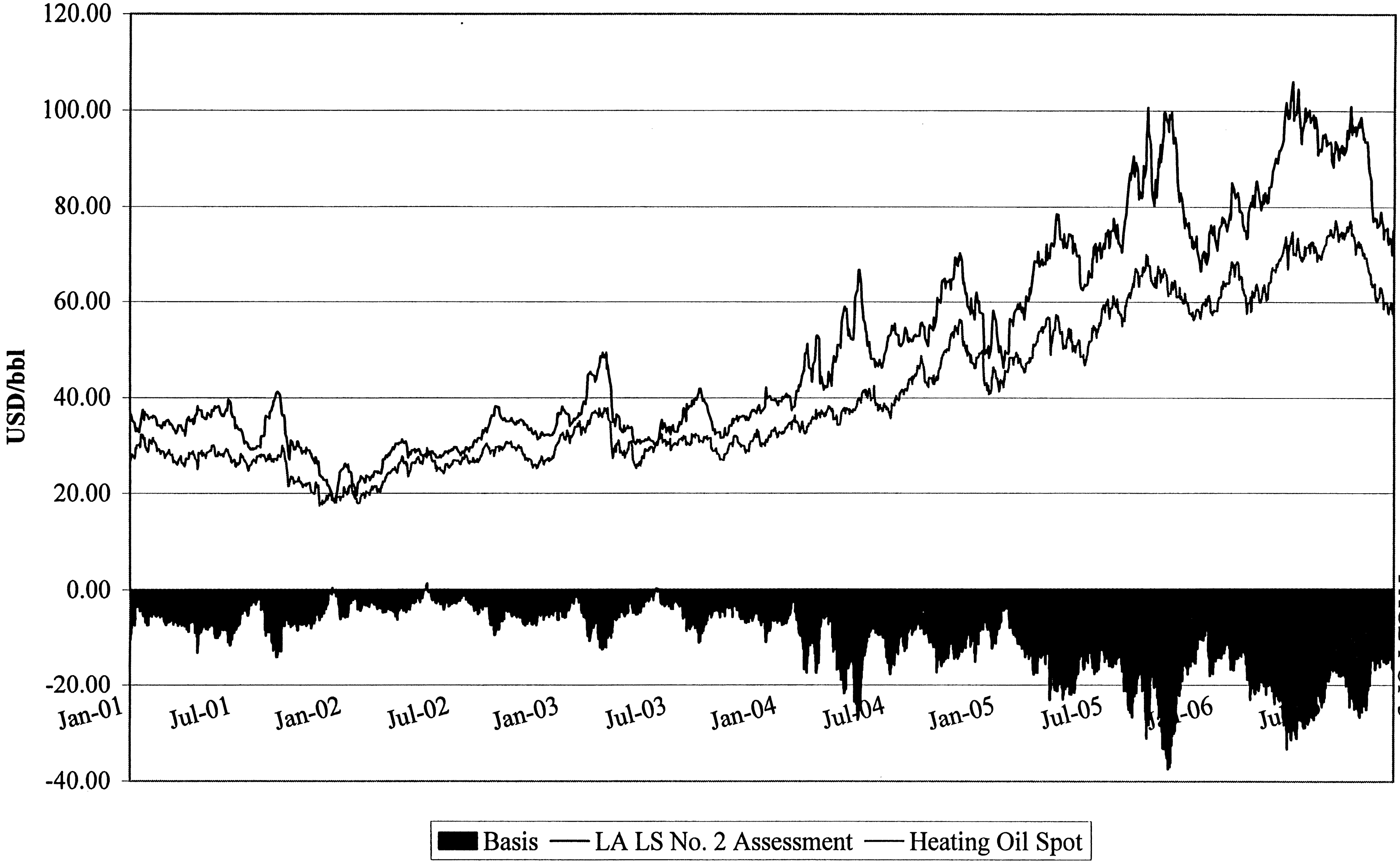
HECO-2206
HISTORIC BASIS GRAPHS (1 of 3)

NERA Economic Consulting

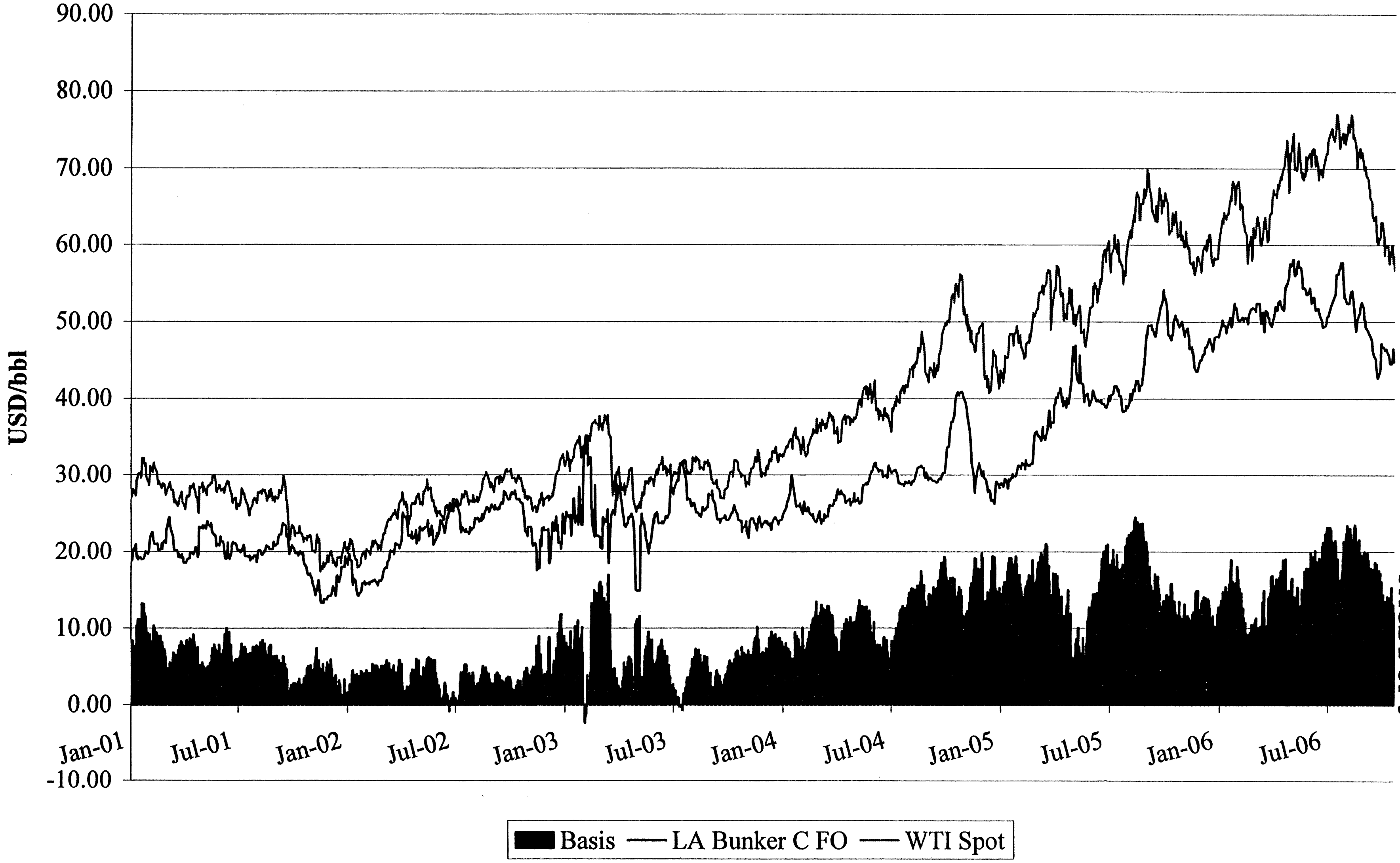
Basis: Heating Oil and LA LS No. 2



HECO-2206
HISTORIC BASIS GRAPHS (2 of 3)

NERA
Economic Consulting

Basis: WTI and LA Bunker C



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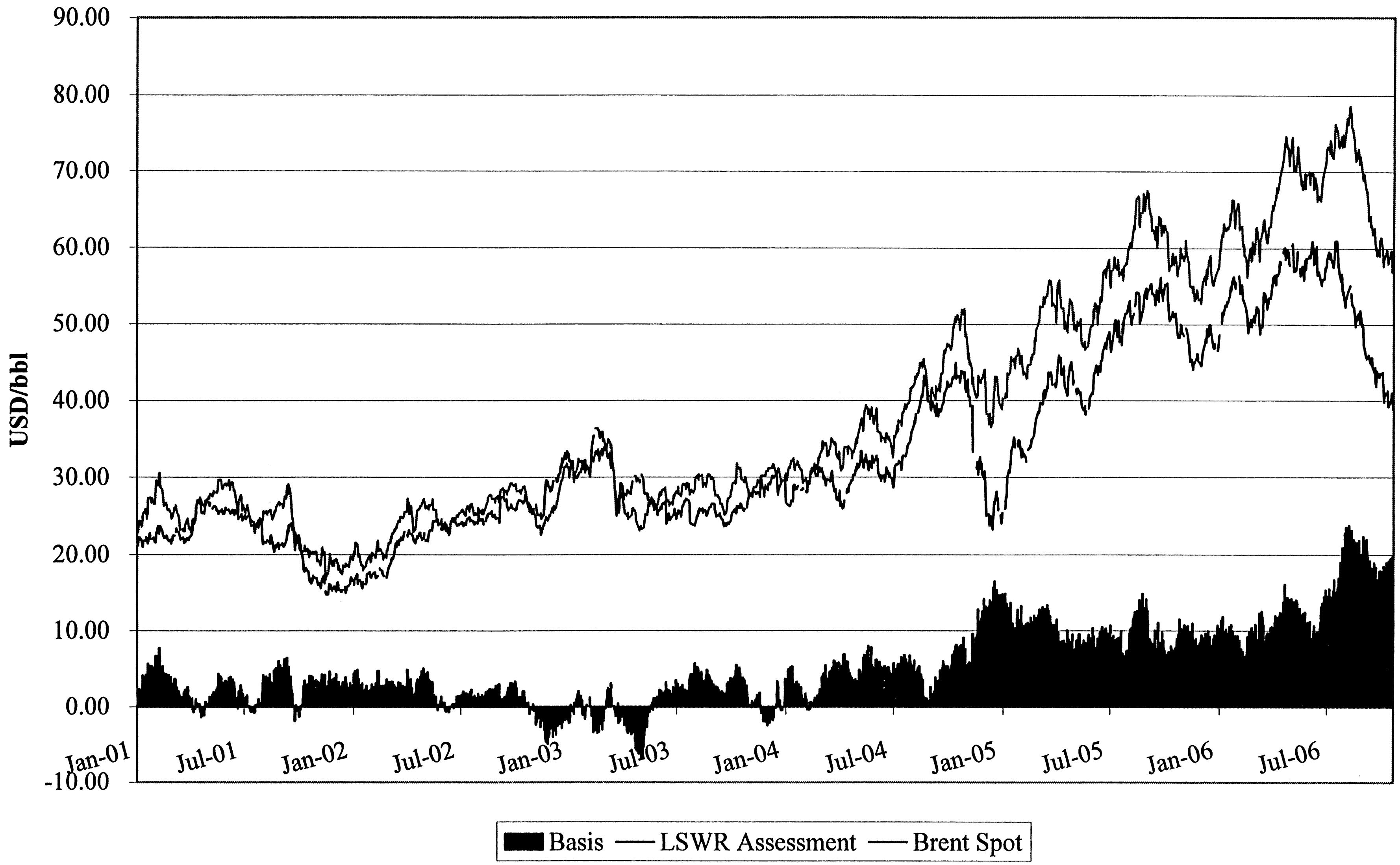
HECO-2206
HISTORIC BASIS GRAPHS (3 of 3)

NERA Economic Consulting

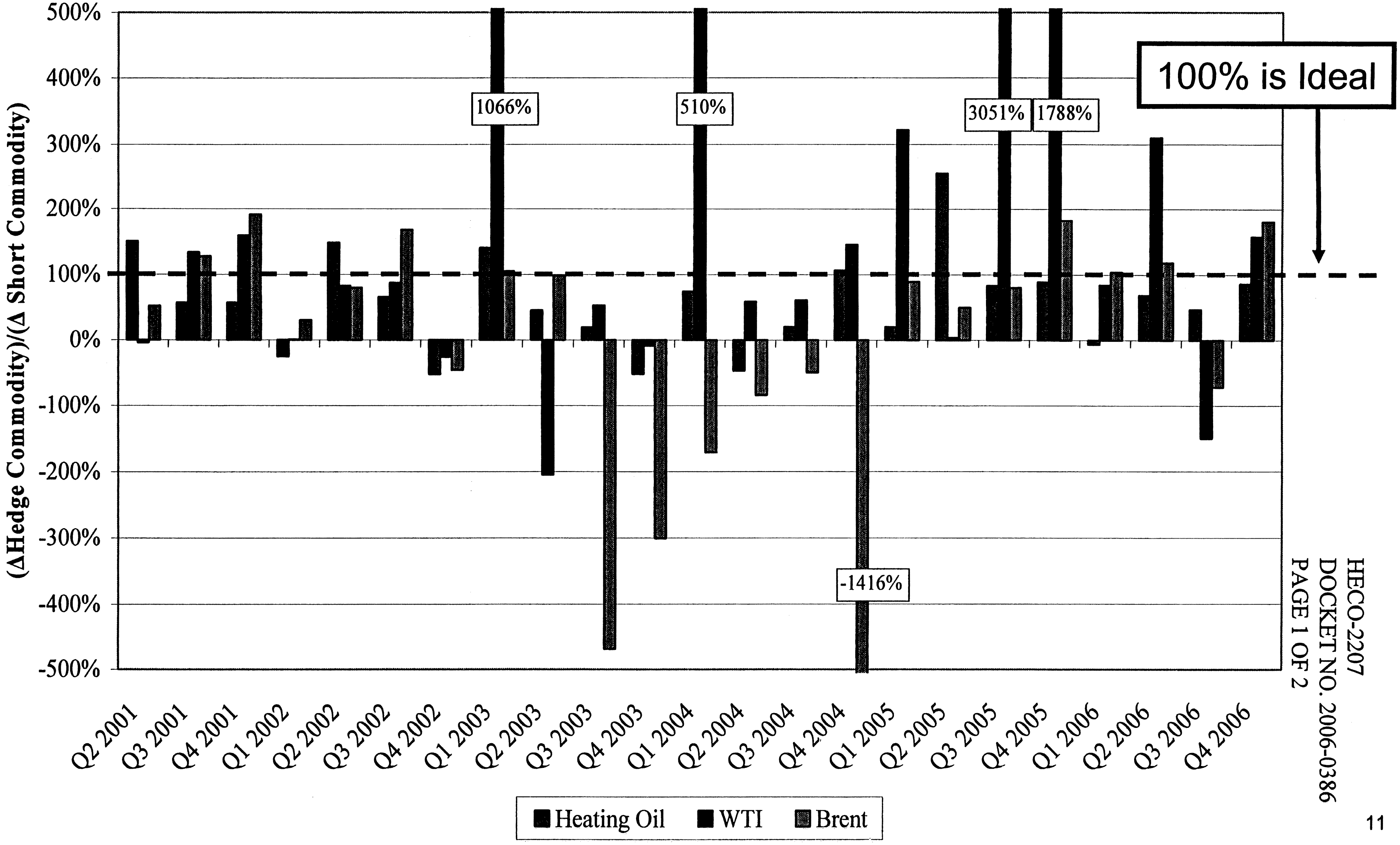
Basis: Brent and LSWR



HECO-2207
HEDGE EFFECTIVENESS (1 of 2)

NERA Economic Consulting

Effectiveness of Quarterly Hedges



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PAGE 1 OF 2

HECO-2207
HEDGE EFFECTIVENESS (2 of 2)

NERA Economic Consulting

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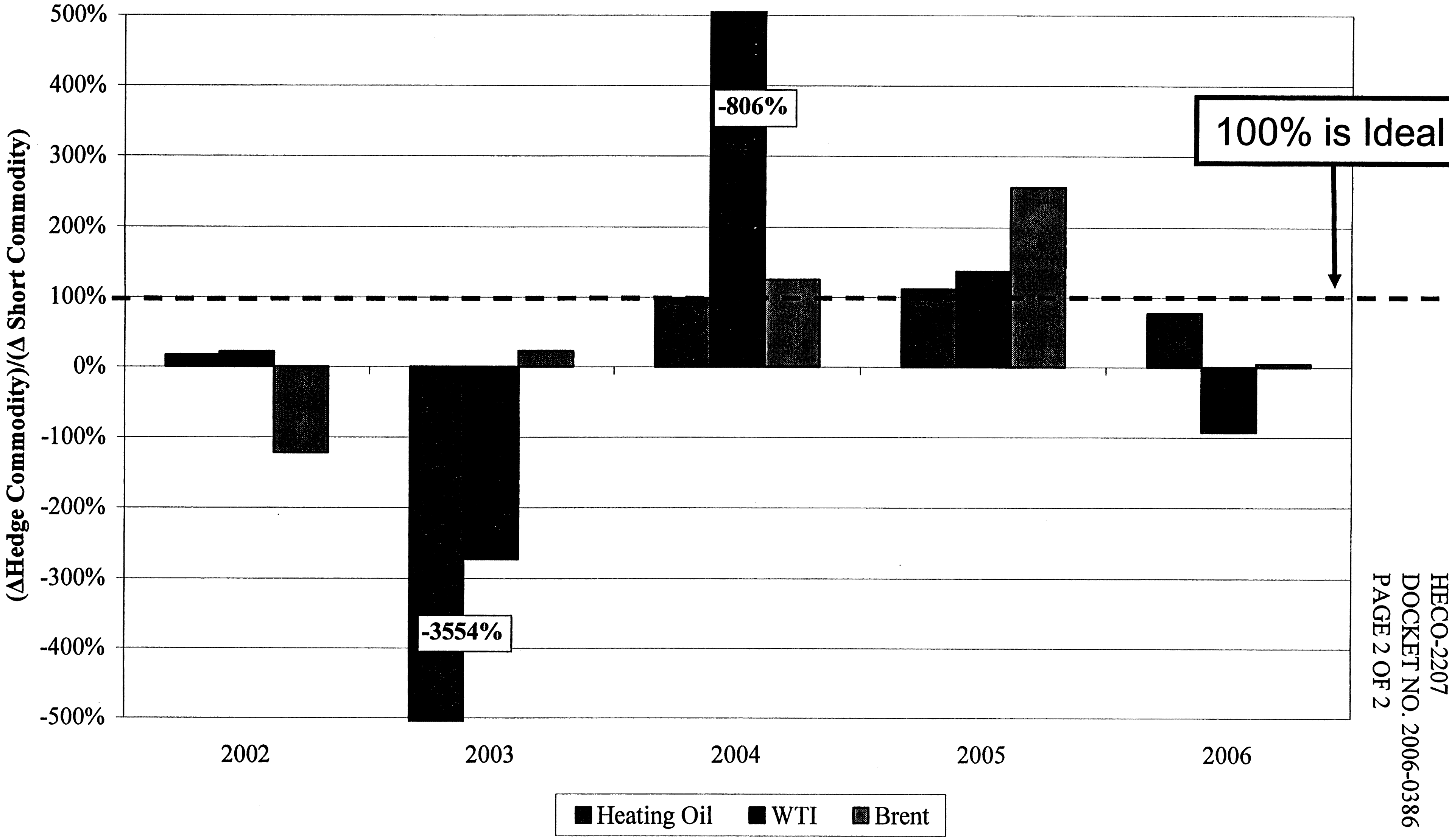
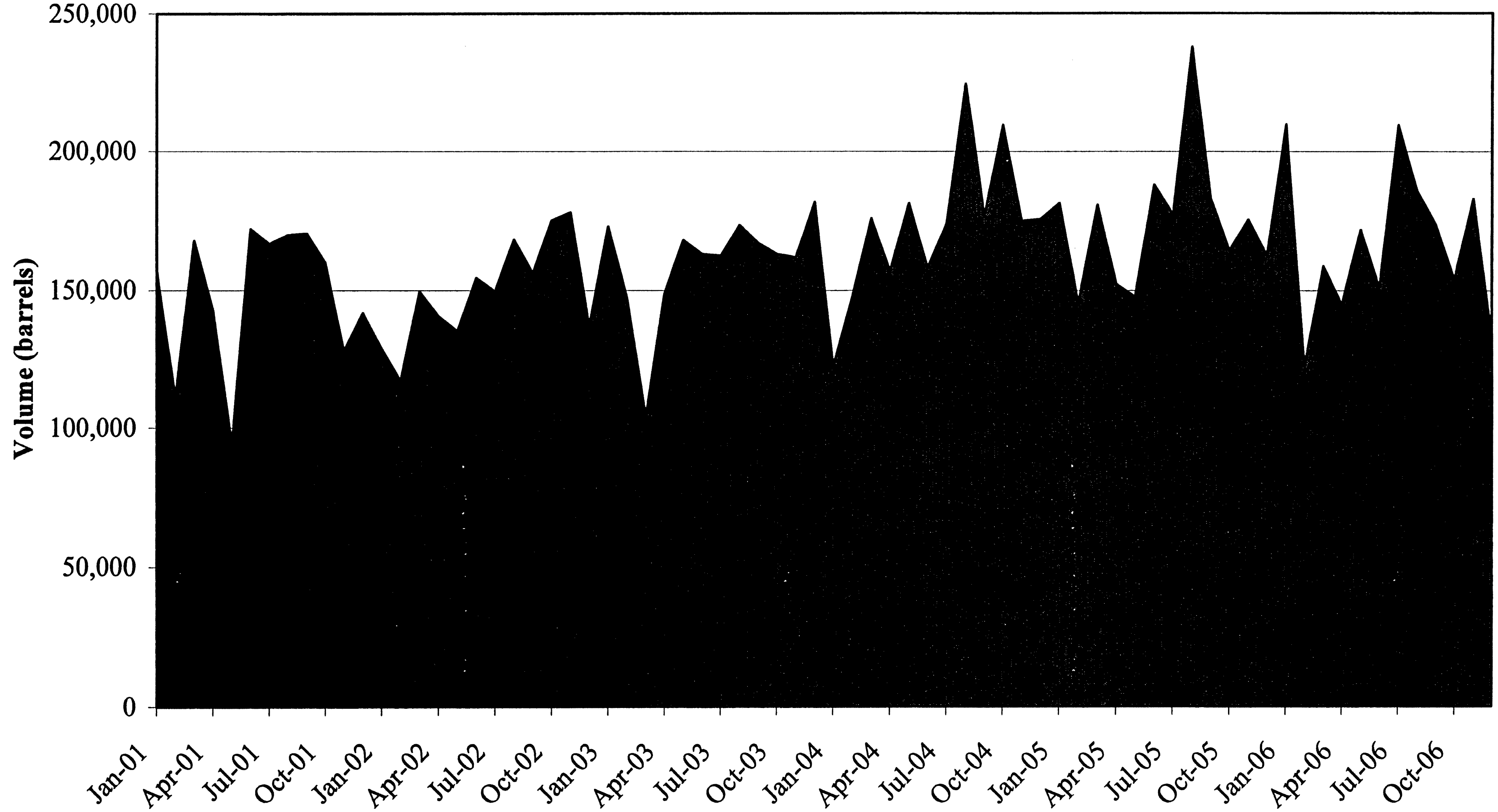
Effectiveness of Yearly Hedges



HECO-2208 HISTORIC QUANTITIES DELIVERED FOR EACH FUEL (1 of 3)

NERA Economic Consulting

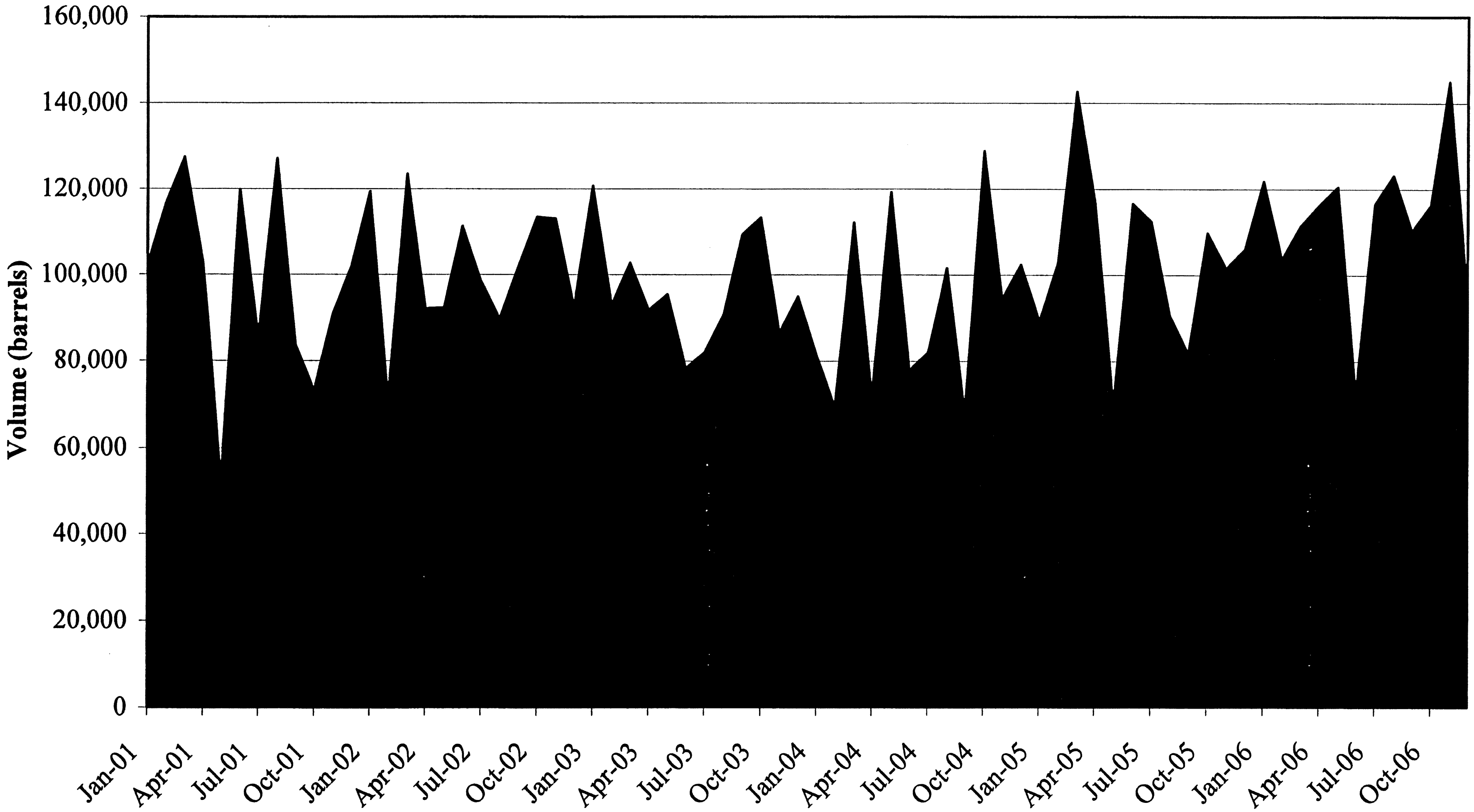
Diesel Oil Deliveries



HECO-2208 HISTORIC QUANTITIES DELIVERED FOR EACH FUEL (2 of 3)

NERA Economic Consulting

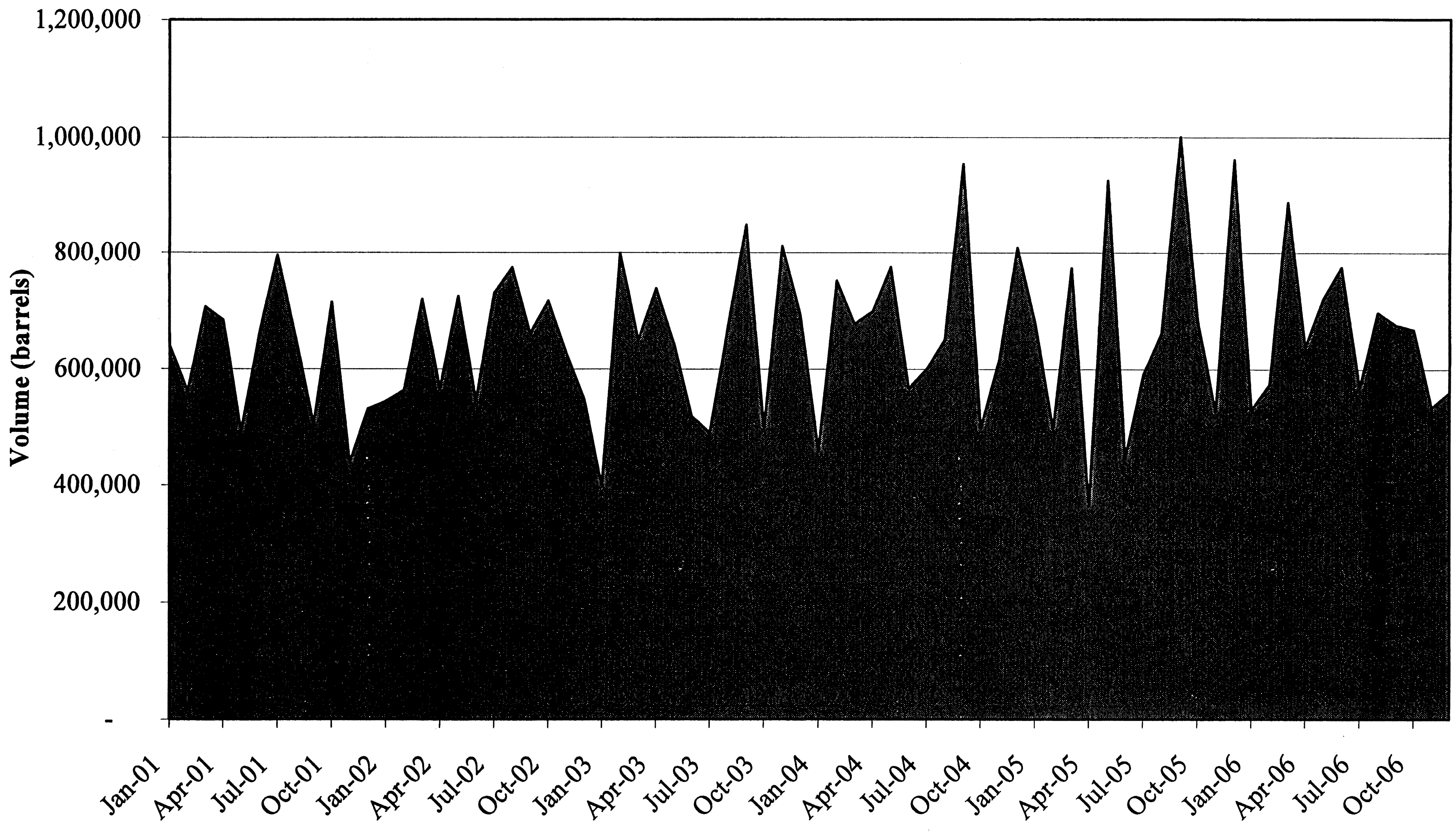
Industrial Fuel Oil Deliveries



HECO-2208 HISTORIC QUANTITIES DELIVERED FOR EACH FUEL (3 of 3)

NERA Economic Consulting

LSFO Deliveries



HECO T-23
DOCKET NO. 2006-0386

TESTIMONY OF
WILLIAM A. BONNET

VICE PRESIDENT
GOVERNMENT AND COMMUNITY AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Results of Operations, including Revenue Requirements, Rate Increase Implementation and Summary

INTRODUCTION

Q. Please state your name and business address.

A. My name is William A. Bonnet and my business address is ASB Tower, 1001 Bishop Street, Suite 811, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am Vice President of Government and Community Affairs for Hawaiian Electric Company, Inc. ("HECO" or "Company"). My educational background and professional experience are provided in HECO-2300.

Q. What testimony will you give in HECO T-23?

A. My testimony in HECO T-23 addresses HECO's Results of Operations, including revenue requirements for test year 2007, and our proposed implementation of the requested increase.

RESULTS OF OPERATIONS

Q. What revenue requirements are reflected in HECO's test year 2007 Results of Operations?

A. HECO's test year 2007 Results of Operations indicate a revenue requirements of $1,501,782,000 (based on August 2006 fuel oil and purchased energy prices) to produce an 8.92% return on HECO's test year 2007 average rate base of $1,214,312,000 at proposed rates, as shown in HECO-2301. At current effective rates, HECO's Results of Operations include total estimated operating revenues of $1,402,226,000 (based on August 2006 fuel oil and purchased energy prices) for test year 2007, or $99,556,000 less than the test year 2007 revenue requirements proposed by HECO.

Q. What does "current effective rates" mean?

A. The term "Current effective rates" means rates that include the Company's 2005

Rate Case Interim Surcharge. On September 27, 2005, the Public Utilities Commission ("PUC" or "Commission") issued Interim Decision and Order No. 22050 in Docket No. 04-0113, HECO's rate case for test year 2005. In the Interim Decision and Order, the PUC authorized the increase of HECO's then present rates by 4.36%, which is currently collected as a percentage of bill surcharge during the interim period before the final decision and order is issued. The Commission has not issued a Final Decision and Order.

A. What are the 2007 test year revenues at rates that do not include the 2005 Rate Case Interim surcharge?

A. The Company estimates that the 2007 test year revenues at "present" rates, i.e., rates that do not include the 2005 Rate Case Interim surcharge, are $1,350,277,000 (based on August 2006 fuel oil and purchased energy prices) as shown in HECO-2302. The difference of $51,949,000 in revenues between present rates and current effective rates is directly attributable to the 2005 Rate Case Interim surcharge revenues. Without the interim surcharge revenues, the Company would require an additional $151,505,000 to earn a proposed 8.92% return.

Q. Are Demand-side Management ("DSM") costs included in the Company's test year revenue requirements?

A. Only DSM costs that are currently being recovered in base rates are included in the Company's test year revenue requirements. Incremental DSM program costs have been removed from the test year. For the purposes of this proceeding, the Company is using the method of cost reocvery that is currently in place where DSM program costs currently being recovered in base rates continue to be recovered in base rates and incremental DSM program costs currently recovered through the DSM surcharge continue to be recovered through that surcharge. Mr. Alan Hee provides a detailed discussion of the treatment of DSM program costs in the test year in HECO T-9.

Q. What would HECO's test year 2007 return on average rate base be for ratemaking purposes without rate relief?

A. Without rate relief, HECO's normalized Results of Operations indicate a rate of return on average rate base of 4.36% based on revenues at current effective rates, and 1.98% based on revenues at present rates (which exclude the 2005 Rate Case Interim surcharge revenues), for the 2007 test year, as shown in HECO-2301 and HECO-2302, respectively.

Q. What rate relief is being sought in this docket?

A. HECO is requesting that the Commission approve rates and charges that are designed to produce an additional $99,556,000 (over revenues at current effective rates) in total operating revenues, as shown on HECO-2301. HECO's proposed rates and charges are included in HECO-106, which is attached to Mr. Alm's testimony, HECO T-1. HECO's proposed rate increases by rate classes for the normalized 2007 test year are shown in HECO-112. This exhibit shows revenues at current effective rates, and the total increase requested in terms of dollars and by percentage.

Q. How much additional operating income will HECO's proposed rates and charges produce?

A. The proposed revenue increase over current effective rates will increase HECO's estimated test year 2007 operating income by $55,372,000 to produce an 8.92% return on our test year 2007 average rate base of $1,214,312 at proposed rates. HECO's supporting testimonies, exhibits and workpapers provide justification for this 8.92% fair return on HECO's property that is used or useful for public utility purposes.

Q. How much of the required additional revenues will go towards paying increased taxes?

A. Approximately 44% of the requested increase in revenues ($44,084,000 of the proposed $99,556,000 increase over current effective rates) will be used to pay increased County, State and Federal taxes.

<u>RATE INCREASE IMPLEMENTATION</u>

Q. How does HECO propose to implement its proposed rate increase?

A. HECO proposes to implement the proposed rate increase in two steps.

Q. What are the two step increases that HECO proposes?

A. The two step increases that HECO proposes are the:

1) Interim Increase, and
2) Final Increase.

Q. When does HECO request that the proposed Interim Increase be made effective?

A. HECO requests that it be allowed to implement its proposed Interim Increase as soon as practicable after the evidentiary hearing is held. Based on the process followed in recent rate cases, HECO is targeting completion of the evidentiary hearing in the third quarter of 2007. HECO is requesting an interim increase as soon as possible. HECO's Results of Operations show that HECO has a need for a rate increase at the beginning of 2007. Therefore, HECO requires the requested increase as near to the beginning of the 2007 test period as practicable to provide the Company an opportunity to earn the rate of return on rate base authorized by the Commission in this proceeding. HECO will determine the amount that it is requesting in the Interim Increase at the close of the evidentiary hearing, based on the evidence before the Commission.

Q. When does HECO propose to make the Final Increase effective?

A. The Final Increase would become effective when the final decision and order in this docket is issued by the Commission. The amount of the Final Increase is to provide for the amount of the total requested revenue increase authorized but not included in the Interim Increase.

Q. What rate design mechanisms does HECO propose to use to implement the Interim and Final Increase?

A. HECO proposes that the Interim Increase implemented prior to the Final Increase be structured as surcharges for the various classes based on a percentage of the customer's base charges (i.e., exclusive of Energy Cost Adjustment charges and other surcharges). HECO requests that the rate design changes proposed in the Application and explained in HECO T-20 be implemented when the Final Increase is authorized. HECO proposes to allocate the final increase in revenues as an equal percentage increase to all rate schedules. As discussed by Mr. Robert Alm in HECO T-1, HECO is proposing to allocate the revenue increase to all rate schedules equally to share the burden among all ratepayers. At the same time, if the amount of HECO's final increase in revenues approved by the Commission is less than the amount requested in this application, the Commission should consider HECO's past criteria for the revenue increase allocation in making its final revenue requirement allocation.

ALTERNATIVE RATEMAKING STRUCTURES

Q. In this proceeding, the Company has requested a general rate increase through a rate case, the traditional ratemaking process. Are there other regulatory or ratemaking structures that could be used to determine rates?

A. Yes. Alternative ratemaking or incentive ratemaking continues to include attractive concepts that may, in some form, be viable options to traditional regulation and cost of service ratemaking. In Act 95[1], as modified by Act 162[2] , the Legislature amended the Renewable Portfolio Standards ("RPS") law and directed that the Commission, by December 31, 2007, "develop and implement a utility ratemaking structure, which may include performance-based ratemaking, to provide incentives that encourage Hawaii's electric utility companies to use cost-effective renewable energy resources found in Hawaii to meet the renewable portfolio standards established in section 269-92 …." (Section 269-95(1), Hawaii Revised Statutes ("HRS"))

Q. What is the status of this effort?

A. On November 1, 2004 the PUC transmitted an Initial Concept Paper, entitled "Electric Utility Rate Design in Hawaii", describing the PUC's intended methodology for fulfilling the legislative mandate in Act 95, and requested comments. According to the paper, the PUC has a legislative mandate to formulate an electric utility rate design that (1) enables the achievement of renewable portfolio standards ("RPS") requiring that renewable energy resources are to have a specific share in the power generation mix by a particular period of time, (2) encourages investments in renewable energy facilities, (3) conforms to the existing regulatory regime, which is cost-of-service regulation, or to alternative regulatory regimes, such as performance based ratemaking ("PBR"), and (4) provides utilities

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[1] Session Laws of Hawaii, 2004

an opportunity to earn a reasonable rate of return. Comments were submitted on behalf of HECO, Hawaiian Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO") (jointly, "the Companies"), as well as 12 other persons and organizations. The first of three planned workshops was held on November 22 and 23, 2004, and involved comments by the PUC's modeling consultant, Economists Incorporated ("EI"), and many of those who submitted written comments.

Q. What was the subject of the second workshop?

A. On July 26, 2005, the PUC transmitted a Second Concept Paper (SCP) authored by EI, entitled "Proposals for Implementing Renewable Portfolio Standards in Hawaii". The paper identified and described seven incentive regulation ("IR") mechanisms. Three were based upon EI's review of renewable portfolio standards ("RPS") programs in other states, and included renewable energy credit trading, alternative compliance fees, and penalties. The last four mechanisms were specially developed for consideration in Hawaii, and were intended to be extensions or variations of the first three and take into account the legislative mandate of the PUC and the specific features of the power markets in Hawaii. fees. These mechanisms included two positive IR mechanisms. Comments were submitted on behalf of the Companies, as well as 8 other persons and organizations in September 2005. On September 23, 2005, the PUC transmitted a technical paper that described the software tools, scenarios, geographic scope, base year, study period,

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[2] Session Laws of Hawaii, 2005

special modeling routines, and the modeling of candidate renewable energy resources in Hawaii. The second workshop was held on October 3 and 4, 2005, and a technical workshop was held on October 5, 2005, and these workshops involved comments by EI, and many of those who submitted written comments. Subsequent to the technical workshop, the Companies submitted additional written comments on October 14, 2005, and provided responses to EI's data requests, and additional forecasts, on October 31, 2005 and November 7, 2005, respectively.

Q. What will be the subject of the third workshop?

A. The Commission has indicated that the goal of the third workshop is to describe and gather comments on the simulation of the power market in Hawaii incorporating, as discussed in the prior workshops, the lessons learned on electric utility rate design under various RPS schemes and PBR regimes, as well as on its use as a tool for electric utility rate design in Hawaii. The PUC envisions that the end result of all the analysis will be a document that forms the basis for a set of rules to be adopted in a conventional rulemaking process to follow, providing input to the PUC's decisions on electric utility ratemaking.

Q. Is PBR considered incentive-ratemaking?

A. Yes it is. The key feature distinguishing incentive regulation from traditional cost-of-service regulation is the relationship between the utility's costs and its rates. Traditional regulation places limits on profits as a substitute for the downward pressure on prices that exists in competitive markets. Thus, utility rates reflect the cost-of-service plus an allowed return on equity. Lower costs translate into lower rates, although possibly with a lag.

Incentive regulation places limitations on price rather than profit, with the expectation that utilities will aggressively cut costs in order to maximize their return. This is accomplished by relaxing the tie between a utility's costs and its rates. Lower costs do not automatically translate into dollar-for-dollar reductions in rates. Incentive regulation allows utilities to retain a portion of cost savings as an inducement for further cost reductions. Consumers benefit by sharing in the cost savings through lower rates than would otherwise exist under traditional regulation. Extending the time frame between rate reviews is another feature of incentive regulation. A longer interval between rate reviews gives the utility added incentives to minimize costs and operate more efficiently.

Q. Has performance-based ratemaking been considered by HECO previously?

A. Yes. The Statement of Position ("SOP") in the 1996 Competition Docket (Docket No. 96-0493) submitted on behalf of the Companies identified performance-based ratemaking as one of three areas which have the potential to provide many of the benefits of competition, while working within the existing regulatory system. In their SOP, the Companies noted that PBR can promote economic efficiency by providing incentives to utilities to reduce costs, while maintaining or improving the quality of service. Price increases to customers who do not have competitive alternatives (such as residential customers) are limited by the price cap mechanism. At the same time, the utility is given the flexibility to charge prices close to marginal costs to customers who have competitive alternatives, which also promotes economic efficiency.

Q. Did the Companies pursue their interest in PBR?

A. Yes. On December 31, 1999, the Companies submitted an application in Docket No. 99-0396 for approval to implement PBR in their respective rate cases following the Commission's final decision in the docket. The main features of the PBR plan proposed in the application included: (1) an index-based price cap mechanism for base rates; (2) an earnings sharing mechanism; and (3) a service quality mechanism. The proposed alternative form of regulation, which was designed to benefit both the Companies' customers and shareholders, was intended to: (1) Strengthen incentives to enhance the efficiency of Applicants' operations; (2) Lower barriers to the development of market-responsive rates and services; (3) Share the benefits of improved performance with customers; (4) Provide more customer choice; (5) Maintain and improve service reliability; and (6) Maintain and improve customer service.

Q. What was the result of that filing?

A. The Commission stated in Order No. 18353, issued February 1, 2001, "At this time, the commission declines to change its current COS/RR methodology for determining their (Hawaiian Electric Company's) rates. However, this does not preclude Applicant from filing a PBR proposal in the future. Accordingly, the commission will dismiss the application without prejudice."

Q. Is HECO proposing to resubmit or revise its PBR application at this time?

A. No. HECO will continue to be an active participant in the collaborative workshops organized and conducted by the Commission and look for further Commission guidance on the appropriateness of such an application.

Q. Are there other forms of alternative ratemaking besides performance-based ratemaking?

A. Yes. Decoupling may certainly be considered alternative ratemaking.

Q. What is decoupling?

A. Revenue decoupling refers to separating the recovery of fixed costs from the amount of electricity sales.

Q. Has the Company addressed decoupling in other regulatory proceedings?

A. Yes, in the Energy Efficiency Docket (Docket No. 05-0069).

Q. What did the Company conclude?

A. In its Opening Brief, filed October 25, 2006, the Company summarized its position on decoupling as an alternative to lost margin recovery. The Companies agreed with the EPA report[3] that the policy decision to separate energy sales from revenues requires a more comprehensive examination, and took the position that is was not practical for that examination to occur within the current scope of the Energy Efficiency Docket. As noted by the EPA Report, decoupling revenue from sales necessarily involves recoupling revenues to another factor (presumably one that is related to costs), and the establishment of a mechanism to adjust rates for the

[3] EPA Review of HECO Interim Demand-Side Management Proposals (Docket No. 05-0069) ("EPA Interim Report"), March 3, 2006. EPA's Comments on Docket No. 05-0069, issued by the Commission, July 26, 2006.

difference. While the concept of decoupling is relatively straightforward, the mechanics of recoupling revenues to another factor, and the implications for customers and the utility, are much more complex. The Companies are open to reviewing some of these considerations in another forum, and/or in a collaborative working group, but the consideration and implementation of a specific decoupling mechanism should be considered by the Commission in a future general rate proceeding.

Q. How is HECO investigating decoupling opportunities?

A. HECO has contracted with Energy and Environmental Economics, Inc. (E3) to examine alternative ratemaking structures and their implications for this utility.

Q. Is this rate case the appropriate forum to review decoupling?

A. No. As HECO stated in its Reply Brief filed November 15, 2006, in the Energy Efficiency Docket, "RMI acknowledged that a schedule of proceedings that would result in a final decision and order within a year is an aggressive schedule." The brief went on to say "One of the parties that would need to participate in the working group would be the Consumer Advocate, and the Consumer Advocate was unable to commit to a schedule for participating in such a working group." In fact, the Consumer Advocate's Reply Brief specifically stated its opposition to decoupling, and the Department of Defense also opposed decoupling. Thus, it will take additional time to consider the issues raised by decoupling.

Q. Are there other approaches to alternative ratemaking?

A. Yes. Automatic adjustment clauses may be considered an approach to alternative ratemaking.

Q. What are automatic adjustment clauses?

A. These are mechanisms to enable recovery of costs which are large, often volatile, not easy to forecast, largely beyond the control of the utility, and expose the utility to adverse consequences if not accurately recovered.

Q. Can automatic adjustment clauses be used with decoupling?

A. Yes. If revenue is to be decoupled from sales, then variations between recorded revenues and the utility's authorized revenue requirement would need to be tracked, with subsequent recovery from, or refund to, utility customers.

Q. Does HECO use automatic adjustment clauses now?

A. Yes. Variations from base rate fuel costs are recovered through the Energy Cost Adjustment Clause, as are purchase power costs. Demand-side management program costs are also recovered through surcharges.

Q. Has there been discussions in recent rate proceedings of other potential automatic adjustment clause applications?

A. Yes. In the 2005 test year rate case, Ms. Tayne Sekimura, HECO's witness on the prepaid pension asset, was asked whether there is a mechanism similar to the Energy Cost Adjustment Clause for the net periodic pension cost ("NPPC"). She responded as follows:

> There could be a mechanism. We did take a look at some other jurisdictions. There is a mechanism by which the NPPC amount is pegged on what was calculated in a rate case. And depending on the actual NPPC that occurs after the rate case there was a mechanism

> in one of the cases whereby there was a true up. It really is based on a deferral. I think there's a lot to understand about that particular mechanism and what the implications are in terms of a true up. For one thing, we would need to understand all of the related components of that. Not only the NPPC, which is the expense portion, but also the impact on what's reflected on the balance sheet as well as getting the external auditors to accept this change.

Ms. Sekimura further expressed a willingness to "explore the possibilities" of a pension cost adjustment, but reiterated that Company needs to know more about "how that really would operate" and "whether it would pass muster with our external auditors…"

Q. Has the Company proposed any new adjustment clauses, for pension costs for example, in this proceeding?

A. The Company is not ready to do that. It needs to extensively examine how these mechanisms would be specifically applied and what their implications would be. Although the Company has not proposed any new adjustment clauses in this proceeding, it may do so in a future proceeding.

Q. Please summarize the status of alternative ratemaking at HECO, with particular attention to this case?

A. As stated earlier, HECO already employs alternative ratemaking in the form of automatic adjustment clauses for fuel, purchase power costs, and DSM program costs. Whether these are to be expanded to pension expenses, or even more broadly to true up sales revenue, is a matter which the Company must explore in greater depth. The fact that the Consumer Advocate and the Department of Defense are on record as opposing decoupling confirms that resolution of broader alternative ratemaking issues is simply not reasonable to expect within the confines of this case. The Company has an urgent need for rate relief. Thus, policy issues on the introduction of broader alternative ratemaking mechanisms in Hawaii should be addressed in a separate future proceeding.

SUMMARY

Q. Mr. Bonnet, do you have any concluding remarks?

A. Yes. HECO has presented substantial evidence in its 23 written testimonies (with exhibits and workpapers) sponsored by 23 different witnesses to support HECO's requested rate increase. HECO's Results of Operations for the normalized 2007 test year base case indicate that a rate increase of $99,566,000 over revenues at current effective rates is necessary to permit HECO an opportunity to earn a rate of return of 8.92% on its average rate base of $1,214,312,000 at proposed rates.

Adequate and timely rate relief will allow HECO to maintain its financial integrity and ability to attract capital for its capital expenditures. Thus, it is essential that the proceeding in this docket progress as expeditiously as possible. HECO urges that the Commission grant:

1) an appropriate Interim Increase as soon as practicable, pursuant to Section 269-16(d), HRS,
2) a Final Increase (which would incorporate an Interim Increase) such that the combined impact of the Interim and Final Increases yields the requested increase of $99,556,000 over current effective rates for the normalized 2007 test year, and
3) approval of the proposed revisions to HECO's rate schedules and rules as submitted by Mr. Young in HECO T-20.

Q. Does this conclude your testimony?

A. Yes.

HAWAIIAN ELECTRIC COMPANY, INC.

WILLIAM A. BONNET

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. (HECO) ASB Tower 1001 Bishop Street, Suite 811 Honolulu, HI 96813	
Position:	Vice President Government & Community Affairs	
Years of Service:	21	
Education:	Vanderbilt University BS Civil Engineering (1965)	
	University of Illinois MS Civil Engineering (1967)	
	University of Texas MBA (1972)	
Previous Positions:	2001-Present	HECO Vice President, Government & Community Affairs
	1996-2001	Maui Electric Company, Limited President
	1988-1996	HECO Manager, Environmental Department
	1985-1988	HECO Director, Engineering Research
	1983-1984	City & County of Honolulu Director of Transportation Services

Previous Positions (continued)	1981-1982	City & County of Honolulu Deputy Director of Public Works
	1972-1980	Austin, Tsutsumi & Associates, Inc. Vice President, Treasurer, Director and Chief Environmental Engineer

Professional Activities:	Hawaii Society of Professional Engineers - Past President
	Engineering Association of Hawaii - Past President
	Hawaii Water Pollution Control Association - Past President
	Hawaii Association of Environmental Professionals – Past Director
	Maui Chamber of Commerce – Director (1997-2000)
	Maui Economic Development Board – Director (1997-2000)
	Land Use Research Foundation of Hawaii – Vice President
Awards:	1996 Engineer of the Year: Hawaii Society of Professional Engineers
	1999 Chi Epsilon Honoree: National Civil Engineering Honor Society
Community Activities:	Metropolitan YMCA of Honolulu – Board Member

Hawaiian Electric Company, Inc.
Results of Operations
At Current Effective Rates
2007
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.92% Return on Average Rate Base
Electric Sales Revenue	1,398,279	98,787	1,497,066
Other Operating Revenue	3,440	769	4,209
Gain on Sale of Land	507		507
TOTAL OPERATING REVENUES	1,402,226	99,556	1,501,782
Fuel	542,961		542,961
Purchased Power	386,108		386,108
Production	68,222		68,222
Transmission	10,491		10,491
Distribution	24,722		24,722
Customer Accounts	12,020		12,020
Allowance for Uncoll. Accounts	1,411	100	1,511
Customer Service	7,176		7,176
Administration & General	72,007		72,007
	320		320
Operation and Maintenance	1,125,438	100	1,125,538
Depreciation & Amortization	79,736		79,736
Amortization of State ITC	(1,321)		(1,321)
Taxes Other Than Income	130,761	8,817	139,578
Interest on Customer Deposits	375		375
Income Taxes	14,292	35,267	49,559
TOTAL OPERATING EXPENSES	1,349,281	44,184	1,393,465
OPERATING INCOME	52,945	55,372	108,317
AVERAGE RATE BASE	1,215,544	(1,232)	1,214,312
RATE OF RETURN ON AVERAGE RATE BASE	4.36%		8.92%

Hawaiian Electric Company, Inc.
Results of Operations
At Present Rates
2007
($ Thousands)

	Present Rates	Additional Amount	Revenue Requirements to Produce 8.92% Return on Average Rate Base
Electric Sales Revenue	1,346,379	150,687	1,497,066
Other Operating Revenue	3,391	818	4,209
Gain on Sale of Land	507		507
TOTAL OPERATING REVENUES	1,350,277	151,505	1,501,782
Fuel	542,961		542,961
Purchased Power	386,108		386,108
Production	68,222		68,222
Transmission	10,491		10,491
Distribution	24,722		24,722
Customer Accounts	12,020		12,020
Allowance for Uncoll. Accounts	1,358	152	1,510
Customer Service	7,176		7,176
Administration & General	72,007		72,007
Gen Excise Tax Rate Incr Adj	320		320
Operation and Maintenance	1,125,385	152	1,125,537
Depreciation & Amortization	79,736		79,736
Amortization of State ITC	(1,321)		(1,321)
Taxes Other Than Income	126,151	13,427	139,578
Interest on Customer Deposits	375		375
Income Taxes	(4,107)	53,667	49,560
TOTAL OPERATING EXPENSES	1,326,219	67,246	1,393,465
OPERATING INCOME	24,058	84,259	108,317
AVERAGE RATE BASE	1,216,188	(1,876)	1,214,312
RATE OF RETURN ON AVERAGE RATE BASE	1.98%		8.92%